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A FEASIBILITY STUDY OF WINDPOWER FOR THE NEW ENGLAND AREA

Final Report

October 1979

Prepared for:

Navy Energy and Natural Resources
R& D Office
Naval Material Command
Washington, D.C. 20360

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A FEASIBILITY STUDY OF WINDPOWER FOR THE NEW ENGLAND AREA

Final Report

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SRI International examined the applicability of large-scale windpower electricity generating systems (WEGS) as an alternative source of energy for the New England States in general and for the U.S. Navy Portsmouth Shipyard at Kittery, Maine, in particular. The Boeing Mod 2 wind machine was selected as representative of current technology in the appropriate size range of 2.5 megawatts (MW) rated capacity. Parametric economic analyses led to the conclusion that WEGS electricity can be at economic parity with the incremental electricity from conventional generators using oil or gas without any

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allowance for a capacity credit, provided that the annual utilization factor for the WEGS is at least 50%. Such utilization appears to be achievable at elevations between 620 and 1,240 m (2,000 and 3,000 ft). About one-eighth of the 35,500 km^2 of air space reviewed in New Hampshire is at such elevations. Nonutility financing and capitalization can halve the costs of WEGS electricity. Nonutility ownership of WEGS is encouraged by recent state and federal legislation. The primary potential WEGS environmental impact, interference with television reception, can be mitigated by installation of cable TV services. The New England grid will suffer generating capacity deficits by the mid-1980s if present trends and attitudes continue. Windpower, however, will not be given capacity credit by the utilities because the wind itself is uncontrollable. Because the Portsmouth Naval Shipyard is capable of meeting nearly all of its own electricity requirements from generators installed at the yard, and because these generators are used in a cogeneration mode, Navy participation in New England windpower development offers neither reliability nor economic advantages.

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CONTENTS

LIST OF ILLUSTRATIONS vii

LIST OF TABLES xi

SUMMARY AND CONCLUSIONS S-1

1. THE NEW ENGLAND WIND RESOURCE 1

Summary and Conclusions 1
Reasons for Considering Mt. Washington 2
Meteorological Data 3
Wind Speed 4
Icing 17
Lightning 19
Terrain Description and Terrain Effects 20

2. TECHNICAL CONSIDERATIONS 27

Summary and Conclusions 27
Options for Wind Turbine Design 28
Economic Trend Analysis 32
Horizontal Axis Wind Turbines 32
Vertical Axis Wind Turbines 37
Capital Cost Uncertainty 39
Estimated Annual Electrical Output 39
MOD 2 Selection 42
Operation and Maintenance 49
Reliability 51
Fracture Hazard 55

3. ECONOMIC CONSIDERATIONS 59

Summary and Conclusions 59
Comparison of Electricity Generating Costs 60

4. INSTITUTIONAL CONSIDERATIONS 79

Summary and Conclusions 79
Public Utility Regulatory Policies Act, 1978 80
Public Utilities Commission of New Hampshire 82
Maine Public Utilities Commission 84
Pending Federal Support 85
Revenue Requirements and Fixed Charge Rates 86
Rates of Return 87
Depreciation Rate 91
Levelized Federal Income Tax Rate 91
Property Taxes and Insurance 93

Investment Tax Credits 94
Potential Regulatory Influences on Wind Power 95
Ownership Alternatives 97
Federal Agencies 99
State-Owned Facilities 99
Municipal Agencies 100
Rural Electric Borrowers 101
Small-Scale Hydroelectric Program 101
Private Owner-Developer 104

5. ENVIRONMENTAL CONSIDERATIONS 109

Summary and Conclusions 109
New Hampshire Ecology 110
Potential Environmental Impacts of Construction Activities at the Turbine Site 111
Potential Environmental Impacts of Wind Turbine Structure and Operation 113
Aesthetics 113
Wind Turbine Noise 115
Potential Safety Risks 115
Effect on Electronic Communications 119
Impact on Aircraft Navigation 124
Effects on Animal Populations 126

6. USER REQUIREMENTS 135

Summary and Conclusions 135
NEPOOL 136
PSNH, CMPC, and NEES 150
Portsmouth Naval Shipyard 165
Potential Windpower Use in the NEPOOL Grid 190

7. TECHNOLOGY STATUS REVIEW 193

Summary 193
Technology Status 193
Hamilton Standard Horizontal Axis Wind Turbine 196
Alcoa Darrieus Design 196
General Electric MOD 1A Progress Report 198
The Schachle Design 198
50-kW Wind Turbine Farm Concept 200
The Giromill 200
Offshore WEGS Feasibility 201

APPENDIX A A-1

ILLUSTRATIONS

1-1 Average Wind Speeds by Months at Mt. Washington and Concord, and the Strongest Daily Average Values Observed During Each Month 6

1-2 Average Wind Speeds at Mt. Washington for Each Day of 1973 Showing the Day-to-Day Variability 8

1-3 Wind Speeds at Mt. Washington and Concord at Each Hour of the Day 10

1-4 Wind Speed Distributions at Mt. Washington by Season 11

1-5 Annual Wind Speed Distributions for Mt. Washington and Grandpa's Knob 12

1-6 Theoretical Wind Distributions for Different Average Wind Speeds Computed According to the Weibull Formula 14

1-7 Estimated Wind Speed Distributions for Different Average Wind Speeds for New England 15

1-8 The Estimated Variations of Annual Average Wind Speed with Terrain Height for Well-Exposed Sites 16

1-9 Daily Average Temperatures on Mt. Washington Throughout the Year 18

1-10 Map Showing the Location of Sectors--One Degree . . . . . . Latitude by One Degree Longitude 21

2-1 Power Coefficients of Various Wind Turbines 31

2-2 WEGS Rating (1-30 kW) Versus Capital Cost 33

2-3 WEGS Rating as a Function of Capital Cost 34

2-4 Cost Improvements for Various Learning Curves 36

2-5 Capital Costs of Vertical-Axis Wind Turbines 38

2-6 Effect of Elevation in Windstream Power at Constant Wind Speed 40

2-7 Wind Shear Behavior 41

2-8 Wind Turbine Output Power as a Function of Wind Speed . . . 43

2-9 MOD 2 Configuration 44

2-10 MOD 2 Power Output as a Function of Wind Speed 46

2-11 MOD 2 Annual Output and Utilization Factors 47

3-1 Windpower Electricity Cost as a Function of Capital Investment 62

3-2 Windpower Electricity Cost as a Function of Operating and Maintenance Cost 63

3-3 Windpower Electricity Cost as a Function of Annual Fixed Charge Rate 64

3-4 Windpower Electricity Costs as a Function of Annual Capacity Factor 65

3-5 Coal-Fired Baseload Service Electricity Cost as a Function of Capital Investment 67

3-6 Coal-Fired Baseload Service Electricity Cost as a Function of Fuel Cost 68

3-7 Coal-Fired Baseload Service Electricity Cost as a Function of Annual Utilization Factor 69

3-8 Oil-Fired Intermediate Service Electricity Cost as a Function of Capital Investment 70

3-9 Oil-Fired Intermediate Service Electricity Cost as a Function of Fuel Cost 71

3-10 Oil-Fired Intermediate Service Electricity Cost as a Function of Annual Utilization Factor 72

3-11 Oil- or Gas-Fired Peak-Load Service Electricity Cost as a Function of Capital Investment 73

3-12 Oil- or Gas-Fired Peak-Load Service Electricity Cost as a Function of Fuel Cost 74

3-13 Oil- or Gas-Fired Peak-Load Service Electricity Cost as a Function of Annual Utilization Factor 75

5-1 Idealized Geometry of RF Interference 123

5-2 Probability of a Bird Striking the Rotor Blades as a Function of its Axial Velocity 129

6-1 Purchased and Generated Electricity, Portsmouth Naval Shipyard-January 1978 to June 1979 187

6-2 Steam and Fuel Oil Use, Portsmouth Naval Shipyard--January 1978 to June 1979 189

7-1 Wind Economics Large Scale Systems 199

A1 Outline of Sector 1 . . . . A-3

A2 Terrain Map for Sector 1 . . . . A-4

A3 Terrain Map of Sector 1 with Elevation Increments of 500 Feet A-5

A4 Terrain Map of Elevations in Sector 1 Between 3000 and 4000 Feet Showing 100-Foot Increments A-6

A5 Terrain Map of Elevations in Sector 1 Between 2000 and 3000 Feet Showing 100-Foot Increments A-7

A6 Terrain Map of Elevations in Sector 1 Between 1000 and 2000 Feet Showing 100-Foot Increments A-8

A7 Outline of Sector 2 . . . . A-9

A8 Terrain Map for Sector 2 . . . . A-10

A9 Terrain Map of Sector 2 with Elevation Increments of 500 Feet A-11

A10 Terrain Map of Elevations in Sector 2 Between 3000 and 4000 Feet Showing 100-Foot Increments A-12

A11 Terrain Map of Elevations in Sector 2 Between 2000 and 3000 Feet Showing 100-Foot Increments A-13

A12 Terrain Map of Elevations in Sector 2 Between 1000 and 2000 Feet Showing 100-Foot Increments A-14

A13 Outline of Sector 3 . . . . A-15

A14 Terrain Map for Sector 3 . . . . A-16

A15 Terrain Map of Sector 3 with Elevation Increments of 500 Feet A-17

A16 Terrain Map of Elevations in Sector 3 Between 3000 and 4000 Feet Showing 100-Foot Increments A-18

A17 Terrain Map of Elevations in Sector 3 Between 2000 and 3000 Feet Showing 100-Foot Increments A-19

A18 Terrain Map of Elevations in Sector 3 Between 1000 and 2000 Feet Showing 100-Foot Increments A-20

A19 Outline of Sector 4 . . . . A-21

A20 Terrain Map for Sector 4 . . . . A-22

A21 Terrain Map of Sector 4 with Elevation Increments of 500 Feet A-23

A22 Terrain Map of Elevations in Sector 4 Between 5000 and 6000 Feet Showing 100-Foot Increments A-24

A23 Terrain Map of Elevations in Sector 4 Between 4000 and 5000 Feet Showing 100-Foot Increments A-25

A24 Terrain Map of Elevations in Sector 4 Between 3000 and 4000 Feet Showing 100-Foot Increments A-26

A25 Terrain Map of Elevations in Sector 4 Between 2000 and 3000 Feet Showing 100-Foot Increments A-27

A26 Terrain Map of Elevations in Sector 4 Between 1000 and 2000 Feet Showing 100-Foot Increments A-28

TABLES

1-1 Monthly and Annual Average Wind Speeds for the Years 1969-1978 5

1-2 Tabulation of Wind Speeds Versus Direction at Mt. Washington 9

1-3 Icing Statistics for Mt. Washington 20

1-4 Summary of the Wind Resource 23

2-1 Wind Turbine Characteristics 30

2-2 MOD 2 Utilization in New Hampshire 48

2-3 Cost Summary for 25-Unit Cluster 50

2-4 MOD 2 Economic Parameters 51

2-5 MOD 2 Design Environment 52

2-6 Summary of the Potential Annual Energy Resource Using MOD 2 54

3-1 Baseline Conditions--Conventional Electricity Generators 76

4-1 Composition of Fixed Charges for Investor-Owned Utilities--Typical Values 88

4-2 Fixed Charge Rate for Various Owners 98

5-1 New Hampshire Statistics 112

6-1 New England Region: 1977 Available Capacity by Fuel Type for Major Utilities 138

6-2 Summary of Capacity Requirements for Major Utilities in the New England States 140

6-3 Summary of Capacity Requirements for Major Utilities in the New England Region 141

6-4 Capacity Requirements for Major Utilities in Connecticut 143

6-5 Capacity Requirements for Major Utilities in Maine 144

6-6 Capacity Requirements for Major Utilities in Massachusetts 145

6-7 Capacity Requirements for Major Utilities in New Hampshire 147

6-8 Capacity Requirements for Major Utilities in Vermont 148

6-9 Capacity Requirements for Major Utilities in Rhode Island 149

6-10 Installed Capacity and Proposed Additions and Retirements for Selected New England Utilities 151

6-11 Public Service Company of New Hampshire Electric Power Sales by Sector 155

6-12 Central Maine Power Company Sales by Sector 156

6-13 New England Electric System Electric Power Sales by Sector 157

6-14 Fuel Cost Projections 159

6-15 Public Service Company of New Hampshire: Capacity Required for Load 160

6-16 Central Maine Power Company: Projected Capacity Required for Load 161

6-17 New England Electric System: Capacity Required for Load 163

6-18 Public Service Company of New Hampshire Generation by Unit 167

6-19 Central Maine Power Company Generation by Unit 169

6-20 New England Electric System Generation by Unit 173

6-21 Public Service Company of New Hampshire Generation by Fuel Type 179

6-22 Central Maine Power Company Generation by Fuel Type 180

6-23 New England Electric System Generation by Fuel Type 181

6-24 Portsmouth Naval Shipyard Fuel Oil Consumption Summary, 1964-1978 185

6-25 Portsmouth Naval Shipyard Month-by-Month Fuel Oil Consumption, 1976-1979 186

7-1 Comparison of WEGS with High Commercial Potential 194

A-1 Symbols Used in Terrain Maps and Altitude Ranges in Feet A-2

SUMMARY AND CONCLUSIONS

SRI International examined the applicability of large-scale wind-power electricity generating systems (WEGS) as an alternative energy source for the New England States in general and the U.S. Navy Portsmouth Shipyard at Kittery, Maine, in particular. The total useful wind resource of the 35,500 km^2 area bounded by latitudes 43 and 45 degrees north and longitudes 71 and 73 degrees west was estimated as a function of altitude. The area considered includes nearly the entire states of New Hampshire and Vermont. The Boeing MOD 2 wind machine was selected for analysis because it seemed to be representative of the equipment currently available for generating electricity from the wind at costs equivalent to the costs of incremental electricity from intermediate- or peak-load service combustion turbines. The MOD 2's performance was used for calculating the amount of energy that could be produced from the identified wind resource. Because economic factors influencing WEGS decisions may differ under different circumstances, parametric analyses of the cost of electricity from WEGS and selected conventional fossil-fuel generating units were prepared to permit us to vary the economic assumptions used for our analysis. Institutional factors such as alternative methods of financing WEGS installations and federal and state government incentives for using alternative (i.e., based on neither nuclear nor fossil fuels) energy production were reviewed. Significant potential environmental impacts of WEGS were considered. The present

generating capacity and future requirements of the New England Power Pool (NEPOOL), three selected utilities, and the Portsmouth Shipyard were analyzed in detail to determine how much windpower might be absorbed by these systems. Finally, the technology status of a variety of wind machines was summarized so that the Boeing MOD 2 could be compared with its competitors.

The significant conclusions drawn from this research are summarized below.

- The Portsmouth Shipyard has no apparent incentives to become involved in windpower development in the Mt. Washington area.
- The available wind resource could support perhaps 1,600 Boeing MOD 2 WEGS, which would provide 4,000 megawatts of generating capacity.
- The annual electricity production of 1,600 units could total more than 14×10^6 megawatt-hours (MWh).
- The projected cost of electricity from the Boeing MOD 2 is 3.4¢/kilowatt-hour (kWh). Thus, MOD 2 electricity is at economic parity with the 2.4-3.2¢/kWh costs for fuel used in intermediate- and peak-load service combustion turbines.
- Municipal or cooperative ownership of WEGS allows capitalization with annual fixed charge rates of 7.5 and 6.3%, respectively, which yield electricity costs of 1.6 and 1.4¢/kWh. Fixed charge rates for WEGS using conventional, investor-owned utility financing yield the above-cited electricity costs of 3.4¢/kWh.
- The most significant environmental impact of WEGS is likely to be interference with television reception. It can be eliminated by cable-TV installations.
- Demand for electricity from the New England grid is going to exceed capacity in the area before 1989 if present trends in its use and attitudes toward construction of new generating capacity do not change significantly. The Navy's own new generating unit at Portsmouth will help to preserve the reliability of the electricity supply for the Shipyard if the anticipated New England capacity deficits materialize. Navy participation in WEGS development would not achieve this reliability goal.
- Installing or purchasing electricity from a WEGS installation in the Mt. Washington area would not be economically advantageous to the Navy.
- A number of other wind machines might be as economical as the Boeing MOD 2.

1. THE NEW ENGLAND WIND RESOURCE

Summary and Conclusions

This research effort required an analysis of the wind resources of the Mt. Washington area of New Hampshire. To include other nearby areas of interest to wind power advocates, SRI expanded the scope of the study to include the surrounding area, whose boundaries are latitude 43 to 45 degrees north and longitude 71 to 73 degrees west. Thus, SRI analyzed the wind resource in an area containing approximately 13,690 mi^2 (35,460 km^2). Specific generator sites were not identified because definitive data on factors such as local wind patterns, accessibility, current ownership, and use are not yet available.

Altitude slices of the terrain were made with the aid of a computer program that also calculated the land areas contained within each slice. The locations of these altitude slices are mapped in Appendix A. SRI prepared estimates of the mean wind speeds versus altitude and the distribution of the wind velocities expected around the mean wind speeds. By combining these factors, the available resource can then be calculated for each altitude slice and for the entire 2 by 2 degree area.

SRI has also estimated the seasonal and diurnal variations of wind speeds at Mt. Washington and Concord to assist efforts at future site selection. Precipitation and icing data have been included for Mt. Washington. Taken together, the data allow the conclusion that the wind resource is greater than that needed for any currently anticipated use.

4(

Reasons for Considering Mt. Washington

It is well known that the summit of Mt. Washington, at an elevation of approximately 6,200 feet (1,890 m), is the most windy inhabited place in the United States. Mountain peaks of similar or greater height in other parts of the world may experience higher winds, but at such places the winds are unrecorded. The strength of the Mt. Washington winds is primarily due to the location of the Presidential Range in the main storm track of eastward moving cyclones that occur regularly throughout the year, with highest frequencies in winter, and to the heights of the peaks compared with their surroundings. Another factor is the shape of the terrain, which evidently causes the wind speed at the summit of Mt. Washington to be significantly higher than the speeds in the surrounding free air at the same altitudes. The strength of its winds suggests that Mt. Washington may be a particularly favorable site for energy generation, because the energy (P) in the wind is proportional to air density (ρ) multiplied by the cube of wind speed (V), i.e.,

$$P \propto \rho V^3 \quad .$$

(However, as mentioned in Section 2, Technical Considerations, the actual power produced by a specific wind generator depends also on rotor performance and generator efficiency.) Because wind speed is cubed, the advantage of stronger winds compared to even slightly lower values is appreciable. On the other hand, wind speeds above the rated speed of a particular generator do not produce additional power, and speeds above the cutout speed cause a shutdown, which results in no power output (see Section 2). Thus, a feasible wind energy system entails both meteorological

factors and the availability of a wind generator designed to operate for that particular range of wind speeds. Current designs are not suitable for the extremely high wind speeds and icing conditions on Mt. Washington; therefore, the meteorological discussion given below encompasses most of northern New England, where wind speeds are less than those on Mt. Washington, but are still within useful limits.

Wind energy generation in Vermont was investigated thoroughly from 1940 to 1945 in the Smith-Putnam study (Putnam, 1948). This study is still a valuable source of data on the wind resource of New England.

Meteorological Data

Wind data for the region are regularly available only for a few sites other than Mt. Washington, namely, Concord, New Hampshire; Burlington, Vermont; and Portland, Maine. Unfortunately, these sites are all airports at low elevations; they typically have low wind speeds. To estimate the wind resource for the area, we need to know the variation of wind speed with altitude. Relevant data are scarce; therefore, we interpolated between the average speeds at low and high elevations in a manner consistent with general meteorological knowledge concerning wind shear in the atmospheric boundary layer. This is discussed later in this section, following a summary of the wind data for the various stations. Another factor of importance to the design and operation of wind energy generators is the frequency of icing, and this will also be discussed in this section.

Wind Speed

We obtained meteorological data from the National Climatic Center (NCC) at Asheville, North Carolina. For the 10-year period 1969-1978, data summaries for Mt. Washington, Concord, Burlington, and Portland were reviewed. The summaries give annual, monthly, and daily average wind speeds, as well as hourly weather reports at Mt. Washington and 3-hour observations at Concord, Burlington, and Portland. Mt. Washington data for 12 months selected at random were punched on computer cards for use by statistical computer programs. This selection of data gives statistics that are quite close to those that would be computed using the entire data sample. The following tabulation lists the month and year of the data that were used:

Jan 1974	July 1975
Feb 1969	Aug 1969
Mar 1971	Sep 1972
Apr 1977	Oct 1976
May 1973	Nov 1978
Jun 1970	Dec 1975

The monthly average values of wind speed and the annual averages are shown in Table 1-1. Concord has winds that are slightly weaker than those at Burlington and Portland, whereas Mt. Washington wind speeds are, on the average, approximately four times higher than those at low-level stations. The annual wind variations at Mt. Washington and Concord are shown graphically in Figure 1-1. This figure also shows how strong the daily average values of wind speed can be during each month. For example, on one day in January the wind speed averaged 100 mph (44.7 m/sec),

Table 1-1

MONTHLY AND ANNUAL AVERAGE WIND SPEEDS
FOR THE YEARS 1969-1978
(Miles per Hour)

	Station			
	Mt. Washington	Concord	Burlington	Portland
January	45.6	7.3	9.0	9.3
February	42.8	7.9	8.4	9.5
March	41.7	8.8	9.0	10.3
April	36.7	8.4	8.6	10.1
May	28.1	7.2	8.2	9.3
June	25.5	6.8	8.1	8.3
July	25.2	6.0	7.7	7.8
August	26.3	5.5	7.2	7.4
September	28.3	5.7	7.8	7.6
October	31.6	6.0	8.4	8.0
November	36.6	6.3	9.1	8.5
December	41.9	7.4	9.3	9.4
Annual	34.2	6.9	8.4	8.8

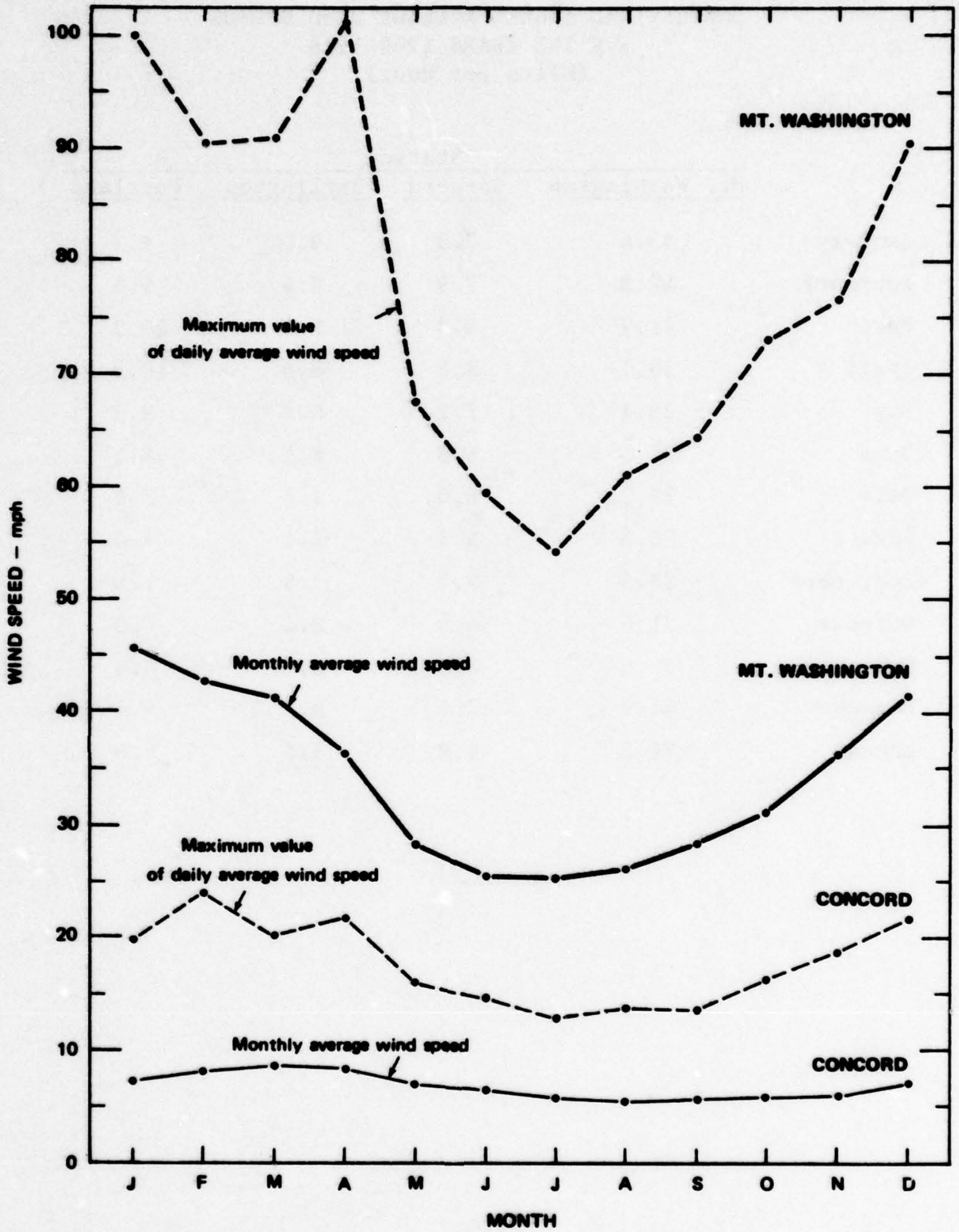

FIGURE 1-1 AVERAGE WIND SPEEDS BY MONTHS AT MT. WASHINGTON AND CONCORD, AND THE STRONGEST DAILY AVERAGE VALUES OBSERVED DURING EACH MONTH

whereas in July the maximum speed averaged for a day was 54 mph (24.3 m/sec). At Concord, the maximum daily averages are all below 25 mph (11.2 m/sec). However, strong winds at Mt. Washington are not continuous, even during the winter, as is evident in Figure 1-2, which is a graph of average wind speeds for each day of 1973. This graph also shows that days having average wind speeds less than 10 mph (4.5 m/sec) occur occasionally, especially during the summer. The distribution of wind speeds versus direction is given in Table 1-2. The preponderance of west and northwest winds is quite marked.

Figure 1-3 shows the diurnal variation of wind speed at Mt. Washington and Concord. Concord has maximum speeds in early afternoon, while Mt. Washington has maximum values at night. In the altitude range from 2,000 to 4,000 ft (620 to 1,240 m), there is probably little diurnal variation in wind speed.

The distribution of wind speeds at Mt. Washington for each season is shown in Figure 1-4 for use in studies of generator design and operation. (For conversion to metric units, use 10 mph = 4.47 m/sec.) The winter curve is especially anomalous in comparison to curves for low level stations. To obtain a distribution curve for an intermediate altitude (at approximately 2,000 ft, 620 m), we used the Smith-Putnam data for Grandpa's Knob, Vermont. The annual curves for this site and for Mt. Washington are shown in Figure 1-5.

The shape of the curve for Grandpa's Knob is very different from the nearly linear curve of Mt. Washington. A linear curve implies an equal probability of all wind speeds, whereas the lower curve implies a preponderance of values near the middle of the range. Wind distributions

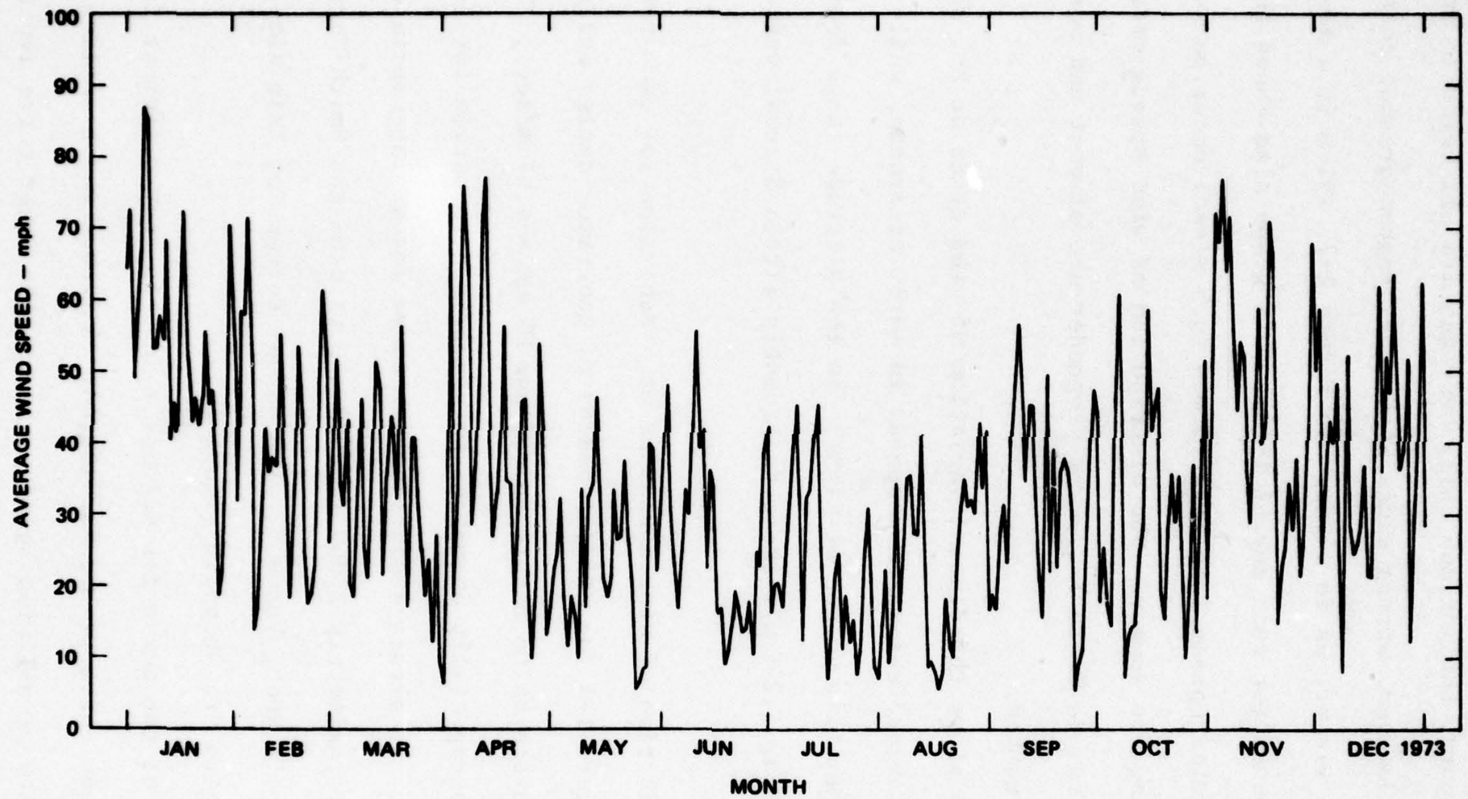

FIGURE 1-2 AVERAGE WIND SPEEDS AT MT. WASHINGTON FOR EACH DAY OF 1973 SHOWING THE DAY-TO-DAY VARIABILITY

Table 1-2

TABULATION OF WIND SPEEDS VERSUS DIRECTION AT MT. WASHINGTON (Percent)

Wind Speeds (Miles per Hour)	Wind Direction N	NE	E	SE	S	SW	W	NW	Total
10	1.5	0.8	0.6	0.6	1.3	1.5	2.8	1.8	10.8
20	1.6	0.5	0.4	0.8	1.4	2.7	7.2	3.5	18.3
30	0.8	0.6	0.6	0.6	1.2	1.9	9.6	3.4	18.7
40	0.4	0.3	0.5	0.4	1.1	1.6	9.2	3.1	16.6
50	0.2	0.3	0.4	0.3	0.4	1.0	7.8	3.5	13.8
60	0.1	0.2	0.3	0.3	0.4	0.4	7.4	3.1	12.2
70	0.0	0.1	0.2	0.1	0.1	0.1	3.9	1.2	5.7
80	0.0	0.1	0.1	0.0	0.0	0.1	1.6	0.3	2.2
90	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.2	1.0
100	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.3
110	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1
Total*	4.5	2.8	3.3	3.1	6.0	9.4	50.5	20.1	99.9

*Calms = 0.1.

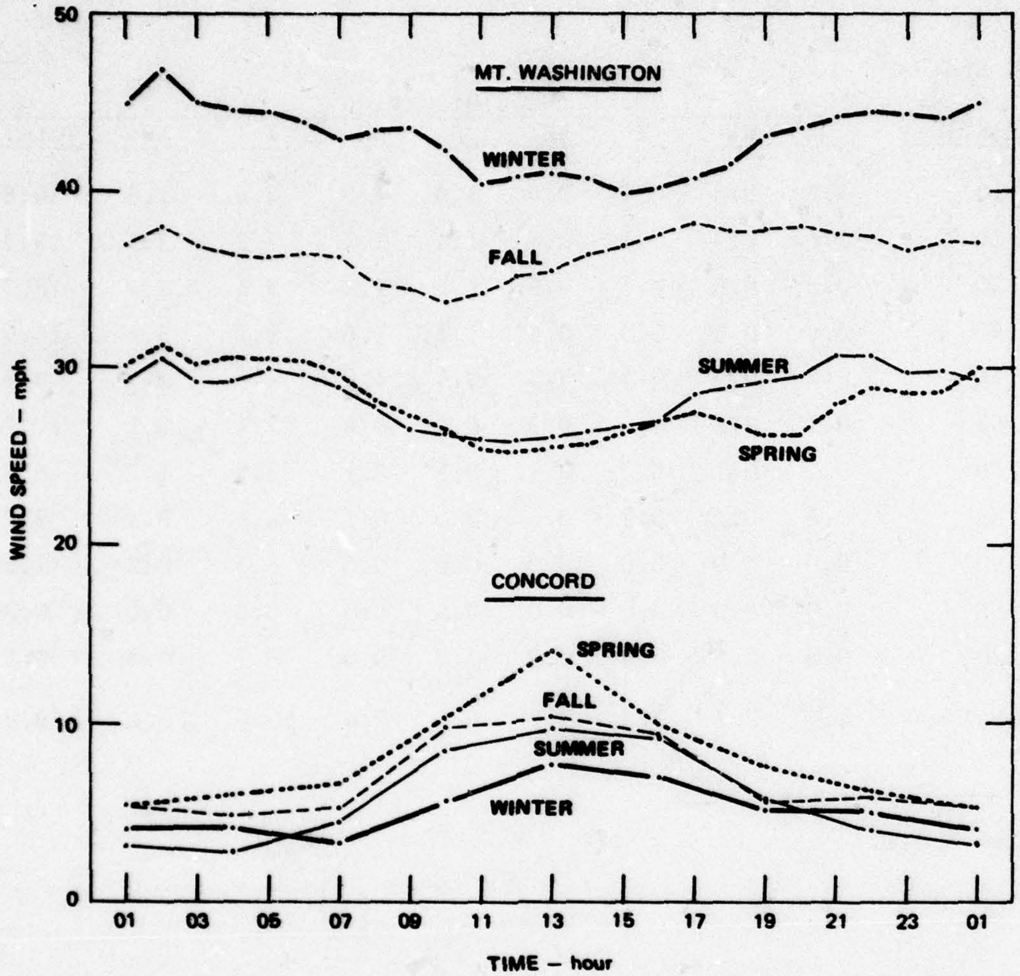

FIGURE 1-3 WIND SPEEDS AT MT. WASHINGTON AND CONCORD AT EACH HOUR OF THE DAY

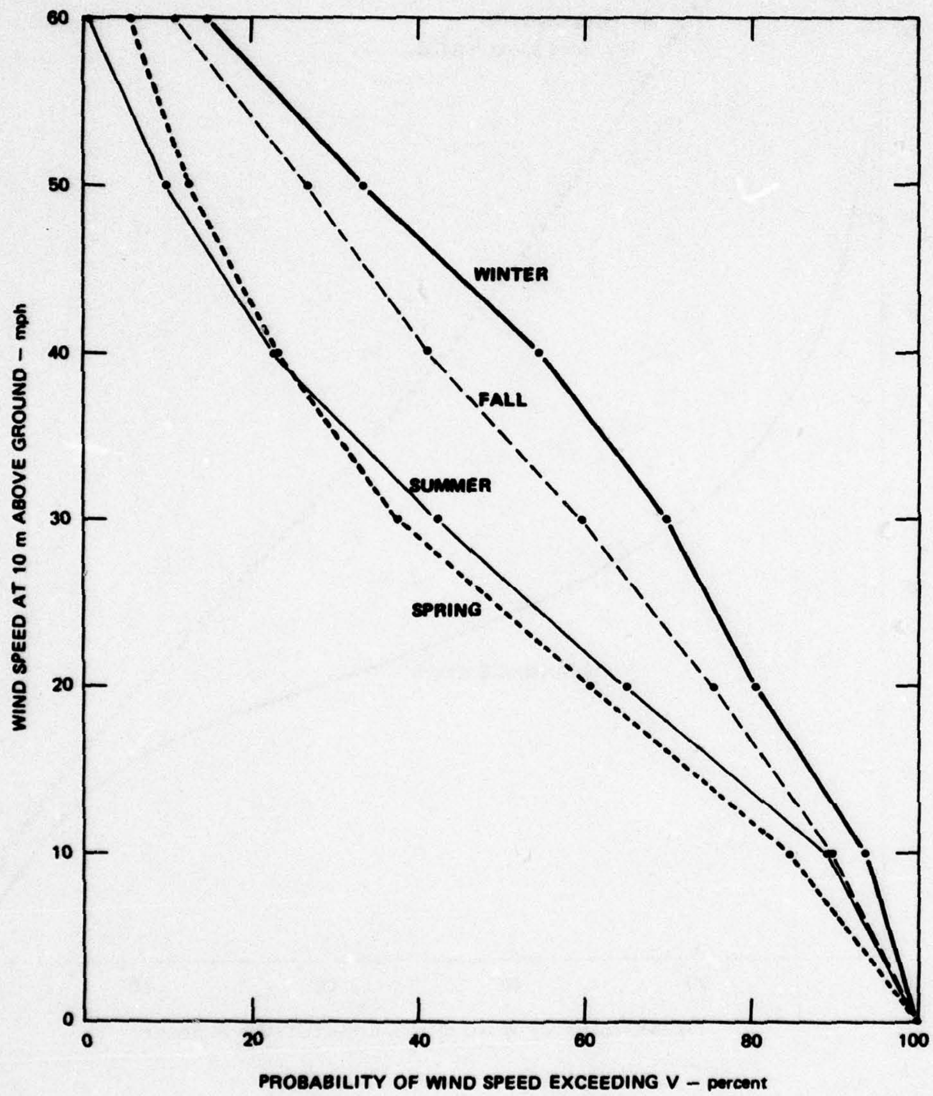

FIGURE 1-4 WIND SPEED DISTRIBUTIONS AT MT. WASHINGTON BY SEASON

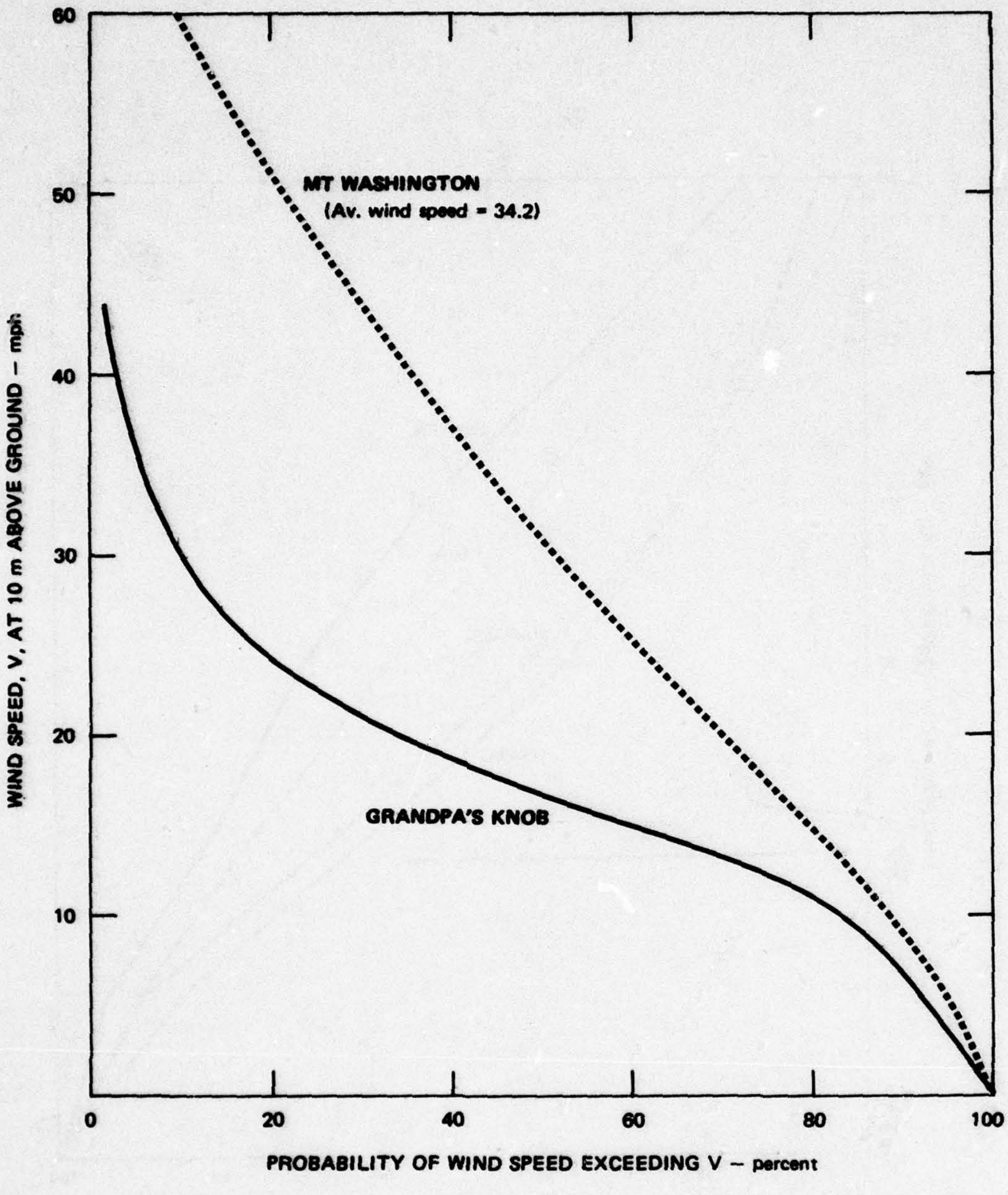

FIGURE 1-5 ANNUAL WIND SPEED DISTRIBUTIONS FOR MT. WASHINGTON AND GRANDPA'S KNOB

of the latter type are predominant. They can be approximated with a normal distribution, but for greater accuracy they are often fitted with the Weibull distribution (e.g., Justus et al., 1976). In the distributions shown below, we have followed the Weibull formulation as discussed by Ramler and Donovan (1979). The formula is:

$$P\,(V_S \geq V) = \exp\,[-(V/C)^K]$$

where $P(V_S \geq V)$ = probability that $V_S \geq V$

V_S = steady wind speed, m/s

V = prescribed value of V_S, m/s

K = constant $\approx$ 1.09 + 0.20 $\bar{V}$

C = constant = $\bar{V} / \Gamma(1 + 1/K)$, m/s

Γ = Gamma Function

$\bar{V}$ = mean wind speed, m/s

As this formula applies to wind speeds at 32 ft (10 m) above ground, we made a correction to obtain the distribution at 160-ft (50-m) height. This correction uses a power law

$$V_{50} = V_{10}\ (50/10)^{\alpha}$$

where $\alpha = 1/6$. The resulting Weibull curves are shown in Figure 1-6. They correspond reasonably well to Grandpa's Knob (Figure 1-5), but not to Mt. Washington. Therefore, for design purposes in New England we have prepared the curves shown in Figure 1-7. At mean speeds above 15 mph (6.75 m/sec), these represent a compromise between Weibull curves and the data of Figure 1-5.

The estimated curve of average annual wind speeds versus altitude is shown in Figure 1-8. Except for the data shown previously in Figures 1-2 to 1-5, not much new information on the variation of wind speed with

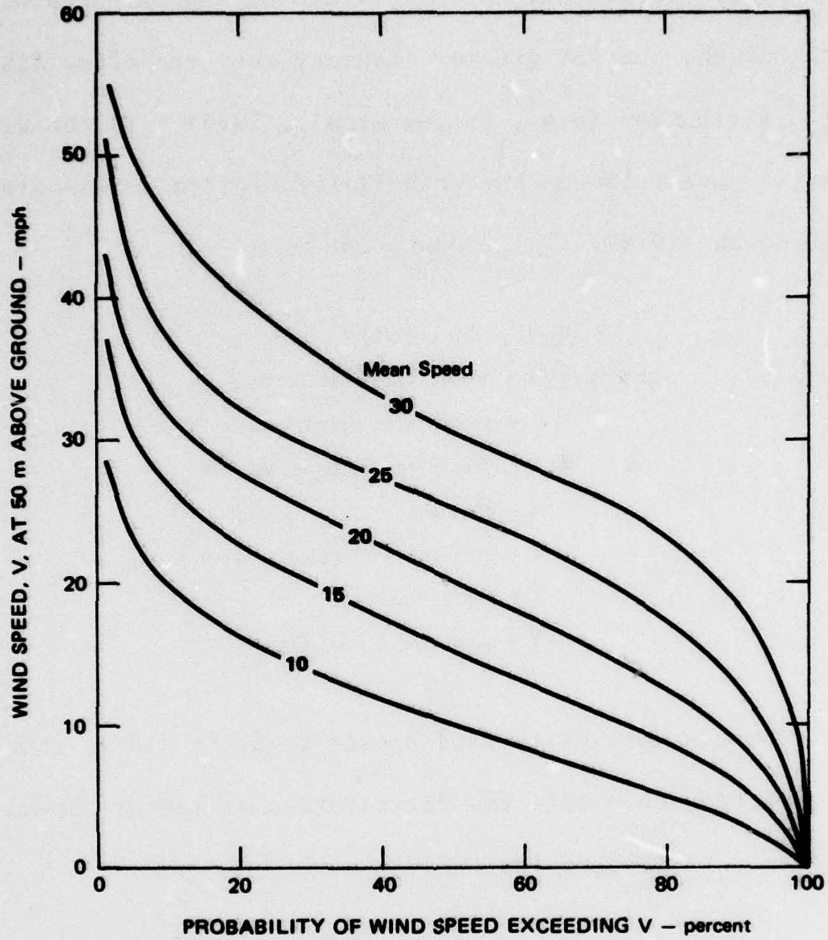

FIGURE 1-6 THEORETICAL WIND DISTRIBUTIONS FOR DIFFERENT AVERAGE WIND SPEEDS COMPUTED ACCORDING TO THE WEIBULL FORMULA

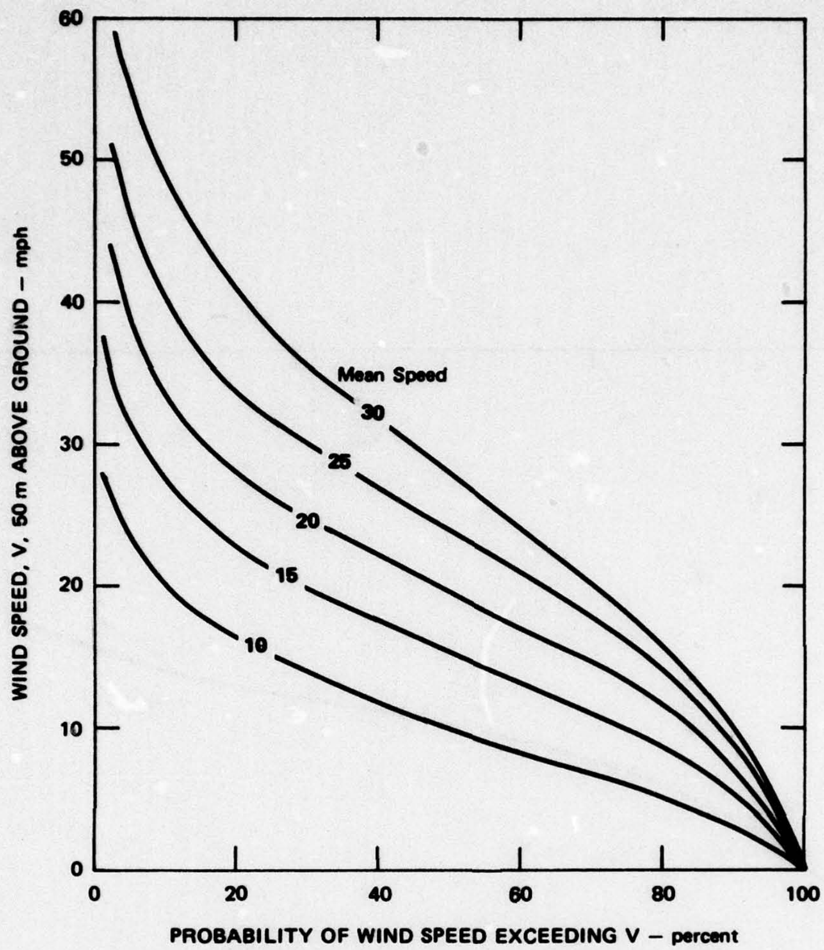

FIGURE 1-7 ESTIMATED WIND SPEED DISTRIBUTIONS FOR DIFFERENT AVERAGE WIND SPEEDS FOR NEW ENGLAND

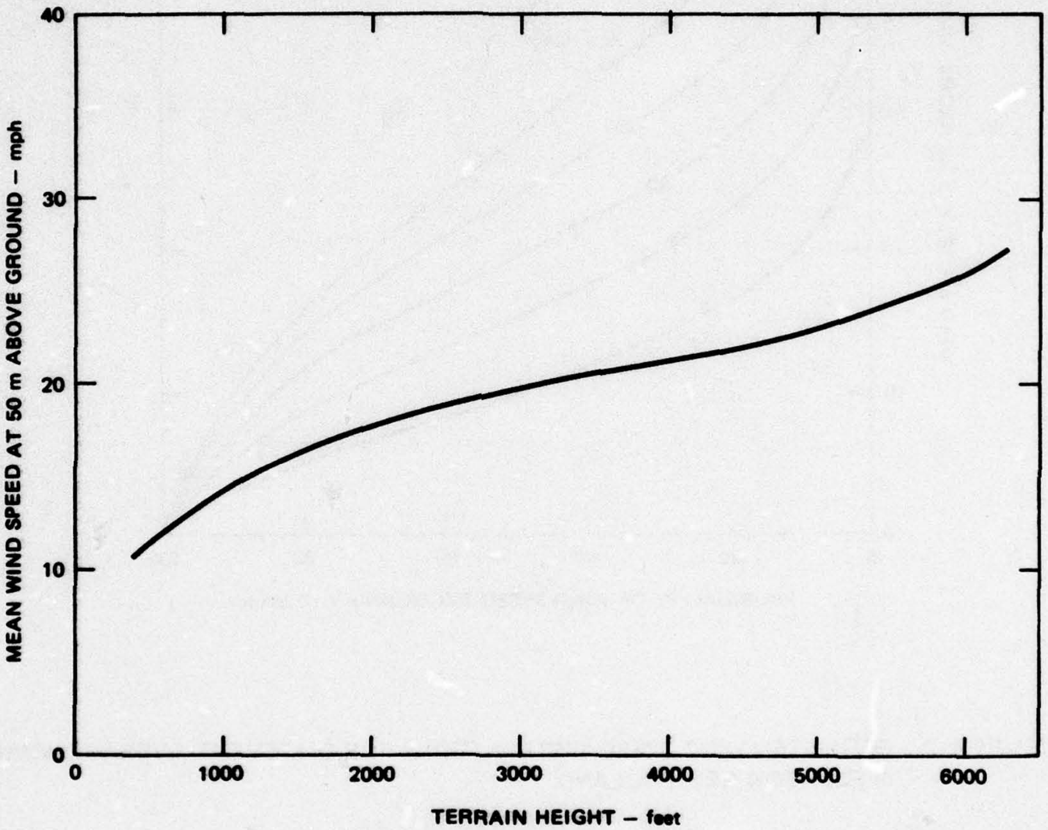

FIGURE 1-8 THE ESTIMATED VARIATIONS OF ANNUAL AVERAGE WIND SPEED WITH TERRAIN HEIGHT FOR WELL-EXPOSED SITES

altitude has become available since the Smith-Putnam study. The exception is for the summit of Mt. Thom at approximately 1,200 ft (372 m) near Holyoke, Massachusetts. Measurements made there (Wendell et al., 1978) show an annual average speed of 16 mph (7.2 m/sec) at 160 ft (50 m) above the ground. Note that the wind speeds of Figure 1-8 apply to well-exposed sites (such as mountain summits, ridges, or gaps) at the altitudes indicated. Complicated local variations in wind speed are produced by local terrain. The effect of such variations on vegetation, and the use of ecological wind speed indicators to determine local wind variations were described by Putnam (1948).

Icing

The second meteorological factor of principal importance in regard to siting wind generators is icing. On the summit of Mt. Washington, icing is often severe. Frozen forms of precipitation (i.e., snow, sleet, rime, glaze) are observed each month of the year. The daily average temperature on the summit exceeds 32°F (0°C) only between early May and early October (Figure 1-9). The high frequency of low temperatures combined with persistent cloudiness and large amounts of precipitation (84 in., 213 cm, water equivalent, per year) results in frequent and severe icing conditions. The types of precipitation that are of concern to wind turbine operations are rime and glaze; snow and sleet do not accumulate on vertical structures.

Rime forms when supercooled water droplets (liquid water at temperatures below freezing) collide with materials and freeze on contact. Rime "feathers" contain entrapped air and appear as snowy, horizontal ice circles. They form into the wind, i.e., in the direction from which the

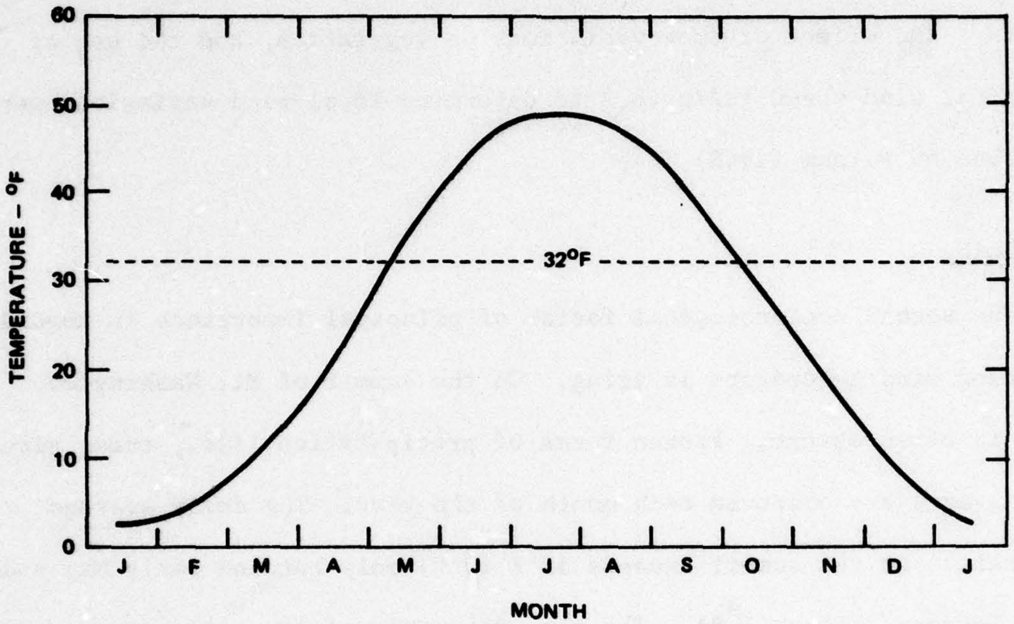

FIGURE 1-9 DAILY AVERAGE TEMPERATURES ON MT. WASHINGTON THROUGHOUT THE YEAR

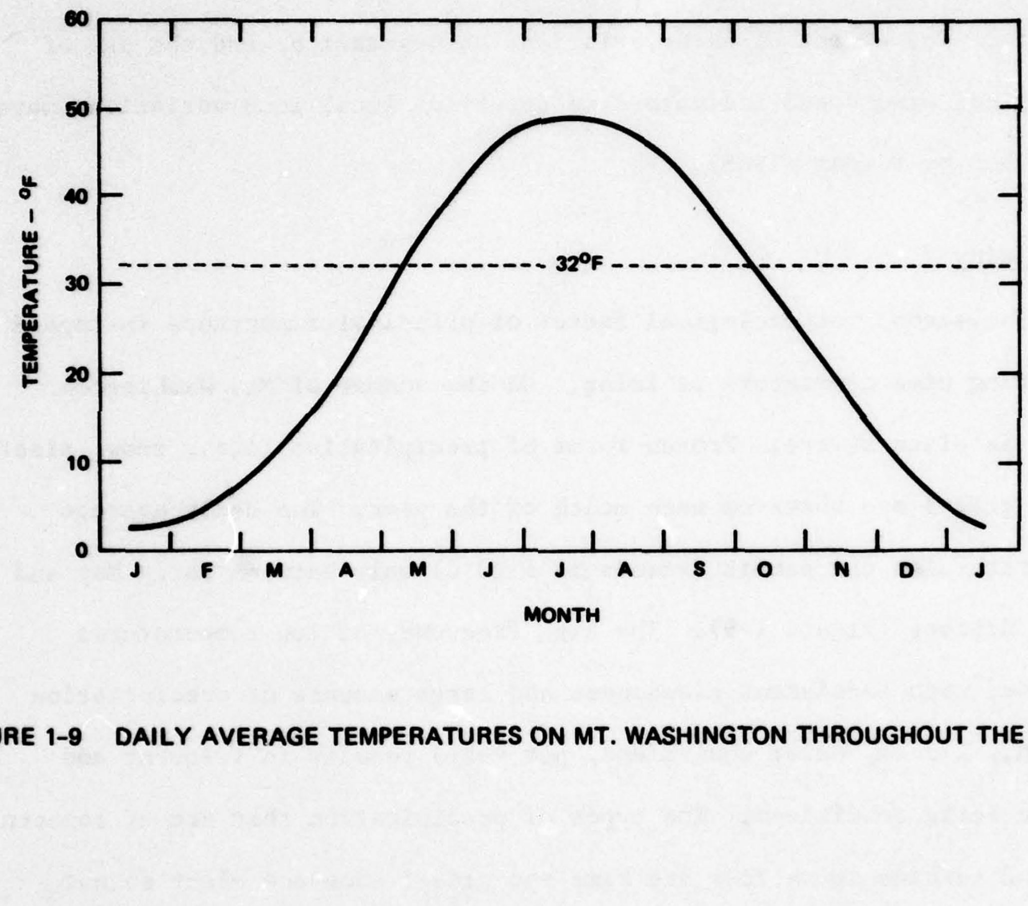

FIGURE 1-9 DAILY AVERAGE TEMPERATURES ON MT. WASHINGTON THROUGHOUT THE YEAR

wind is blowing. On the Mt. Washington summit, rime feathers up to 6 ft (1.8 m) in length have formed (Howe, 1979). Some riming occurs during more than half of the days in the months from October through April. In November 1976, riming occurred for 186 consecutive hours.

Glaze forms when raindrops fall onto frozen surfaces and freeze. Glaze is clear ice that is much denser than rime. On sections of the Mt. Washington summit, glaze accumulations of 6 to 12 in. (15.2 to 30.5 cm) have been observed (Howe, 1979). Glaze occurs during all months with maximum frequencies between September and June. It occurs less frequently than rime: usually less than 5 days per month have glaze. Glaze formation occasionally occurs for 12 consecutive hours, and periods of formation as long as 24 hours have been observed. On Mt. Washington severe icing occurs down to elevations of 3,000 to 4,000 ft (930 to 1,240 m) (Gosselin, 1979). A statistical summary of icing frequency (including both rime and glaze) is given in Table 1-3.

Both rime and glaze icing are infrequent at the standard weather reporting stations of New England because they are at low altitudes. Interpolation of icing frequencies between low altitudes and the elevation of Mt. Washington is difficult. As a first approximation, icing frequency and severity can be assumed to increase steadily with altitude. Therefore, throughout New England at altitudes above 3,000 ft (930 m), icing should represent a significant problem to wind generators.

Lightning

Lightning associated with thunderstorms is another meteorological factor of interest. It can damage wind turbines, especially because structures located on mountain summits are very susceptible to strikes.

Table 1-3

ICING STATISTICS FOR MT. WASHINGTON

	Percent of Observations With Icing				
	Trace	Light	Moderate	Heavy	Total
Winter	11	13	4	1	29
Spring	2	10	4	1	17
Summer	1	1	1	1	4
Fall	4	14	4	1	23

Source: A. Smith, President of the Mt. Washington Observatory, personal communication (July 1979).

Thunderstorm frequencies are fairly uniform throughout New England except for slightly higher frequencies along the coast. Thunderstorms can occur during any month of the year but are most common beginning in the late spring and continuing through the early fall. July has the highest frequency of thunderstorm days with an average of five.

C. Terrain Description and Terrain Effects

The terrain maps in Appendix A illustrate the altitude slices of the sectors studied. The sectors are outlined in Figure 1-10. From these maps the general terrain character can be determined. Also, the legends shows appropriate values of mean wind speed as taken from Figure 1-8. However, these maps do not account for local variations in wind produced by small terrain features. Such small features produce local wind speed differences that may be as much as ±15 percent of the wind speeds of Figure 1-8. In searching for favorable sites for wind

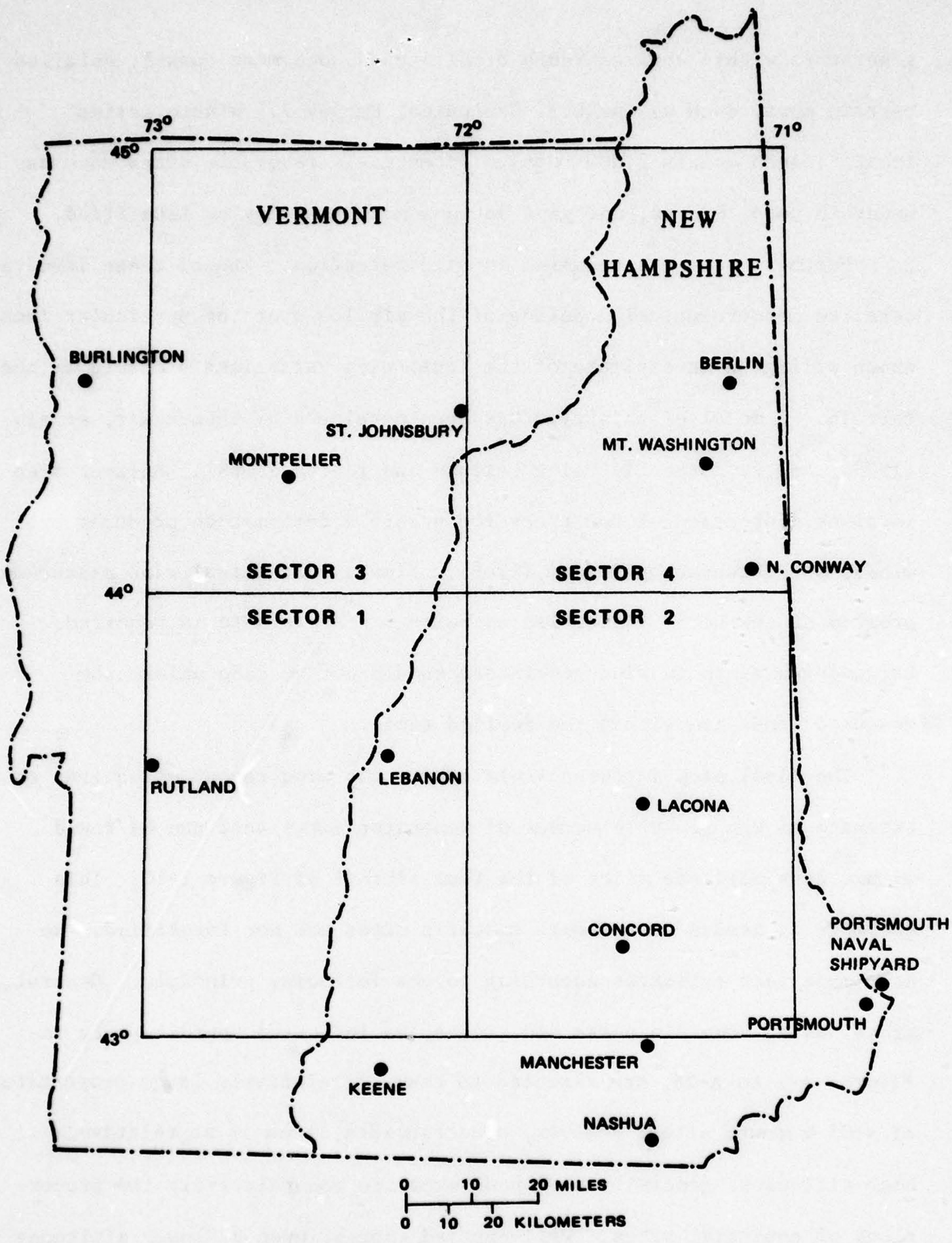

FIGURE 1-10 MAP SHOWING THE LOCATION OF SECTORS — ONE DEGREE LATITUDE BY ONE DEGREE LONGITUDE

generators within a given range of altitudes, one must consult detailed terrain maps, such as the U.S. Geological Survey 7.5 minute series (scale 1 inch equals 2,000 feet). Potentially favorable sites such as mountain tops, ridges, and gaps between mountains may be identified.

Further steps are required in site selection. One of these involves detailed meteorological modeling of the airflow over the particular locale, which will give an estimate of the local wind variations produced by the terrain. A model of this type has been developed by Bhumralkar, et al. (1978), and is currently being refined and tested at SRI. Another step involves inspection of the trees for possible deformation produced by winds, as discussed by Putnam (1948). Finally, an actual wind measurement program at the sites identified as being most favorable is required. Large investments in wind generators should not be made unless the measured winds are within the desired range.

The final step in our calculation of the wind resource requires an estimate of the probable number of generator sites that can be found within each altitude slice of the four sectors of Figure 1-10. This estimate is needed even though specific sites are not identified. We have made such estimates according to the following principle: General areas having mountain peaks and ridges, as indicated approximately in Figures A-1 to A-26, are expected to contain relatively large proportions of well-exposed sites; however, mountainsides, even if at relatively high altitudes, generally have poor exposure and relatively low proportions of potential sites. Well-exposed ridges, even at lower altitudes, may contain some good sites. With these guidelines, and lacking further detailed information, we prepared Table 1-4, which is a summary of the

Table 1-4

SUMMARY OF THE WIND RESOURCE

Sector	Altitude Range ($ftx10^3$)	Area (mi^2)	Site Factor	Possible Number of Generators	Approximate Average Wind Speed (mph)	Remarks
1	3-4	16	0.25	16	21	Moderate icing
1	2-3	350	0.20	280	19	
1	1-2	2,140	0.02	171	16	
2	3-4	13	0.25	13	21	Moderate icing
2	2-3	122	0.20	98	19	
2	1-2	777	0.03	93	16	
3	3-4	17	0.30	20	21	Moderate icing
3	2-3	261	0.25	261	19	
3	1-2	2,057	0.02	164	16	
4	5-6	3	0.50	6	24	Very severe icing
4	4-5	20	0.30	24	22	Severe icing
4	3-4	150	0.15	90	21	Moderate icing
4	2-3	761	0.10	304	19	
4	1-2	2,161	0.01	86	16	
Total		8,846		1,626		

wind resource. In the first row of the table, the area of Sector 1 lying between 3,000 and 4,000 ft (930 and 1,240 m) is 16 mi^2 (41.6 km^2), as shown in Figure A-4. These are the highest peaks in the sector. We assume that 25% of this area (4 mi^2, 10.4 km^2) is suitable for generator sites. Also, as explained in Section 2, we assume that on the average four generators can be located within a square mile in a suitable are. Thus, the possible number of generators for this altitude slice is 16. According to this approximate method, we expect that 1,626 specific generator sites (more or less) can be located by further study (using methods mentioned earlier), and these generators could provide approximately 4,065 MW of wind energy, when operating at their rated capacity.

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2. TECHNICAL CONSIDERATIONS

Summary and Conclusions

To convert the kinetic energy of the wind into a useful form, a wide variety of machines have been developed. These range from the familiar, multibladed agricultural windmill, to more modern, high-speed two-bladed wind turbines. Each design has advantages, depending upon the local wind characteristics and the particular energy need being met.

This study focuses on machines capable of producing electrical power compatible with the requirements of utility systems. Wind turbine designs were briefly analyzed, and the more efficient designs, including the high-speed, two-blade design and the Darrieus design, were chosen for further economic study.

In determining the most economical wind turbine, SRI considered the total annual output of the machine to be as important as the initial cost. The factors influencing annual energy output were analyzed. For the high-speed, two-blade design, machines rated between 1 MW and 10 MW appear to have the lowest costs per kilowatt. These machines, commonly referred to as large wind turbines or megawatt-scale turbines, are most attractive in areas with high wind speeds. The analysis of the Darrieus two-bladed wind turbine indicated a minimum cost per kilowatt would occur for machines rated at 300 KW.

The MOD 2 wind turbine, being developed for the U.S. Department of Energy by Boeing, was selected for a more detailed examination of wind turbine characteristics, economics, and implementation because of its projected low energy costs and the availability of detailed technical information. The MOD 2 is an advanced 2.5-MW wind turbine with a rated wind speed of 27.5 mph (12.3 m/sec); cut-in speed of 13 mph (5.8 m/sec); and a cut-out speed of 45 mph (20.1 m/sec). The prototype of this machine is expected to be in service by mid-1980. The first production unit is estimated to cost $1,610 per kilowatt installed. The 100th production unit is estimated to cost $816 per kilowatt installed, in 1979 dollars. At this estimated cost and with favorable utilization of its capacity, the MOD 2 can generate electricity at costs that are competitive with the incremental electricity costs of new power plants fired with more traditional fuels. The 2.5-MW size is comparable to the peak purchased power at the Portsmouth Naval Shipyard and is large enough to be considered for utility-owned wind farms. Therefore, SRI used the performance characteristics of the MOD 2 in combination with the New England wind resource to calculate the net generating capability in the area surrounding Mt. Washington in New Hampshire. This generating capability amounts to about 4,000 MW and exceeds the amount of wind electricity that can be absorbed by the regional utility grid in its intermediate-service load.

Options for Wind Turbine Design

A variety of wind machines convert the motion of the wind into rotational motion. In principle, any of these can be used to generate

electricity. However, in practice, some designs are more attractive because of design factors that affect complexity, efficiency, material requirements, and, particularly, cost.

Wind turbines can be divided into distinct groups: horizontal axis (HAWT) and vertical axis (VAWT). The HAWT rotor blade has a horizontal axis rotation, while the VAWT rotor axis is vertical. Table 2-1 summarizes some important design features of each type. By design, HAWT is more complex because it must be rotated to face the wind. This necessitates a yawing mechanism to rotate the wind turbine. In a HAWT unit, the rotor and nacelle, which includes the gear box, yawing mechanism, and generator, is mounted atop a tower. In contrast, a VAWT is usually supported by wires, with the generator mounted on the ground, providing for simpler design and construction.

The VAWT is not self-starting; however, when the VAWT is connected to the utility this serious drawback is avoided because the VAWT can be started by using the generator as a motor; the energy so used is insignificant.

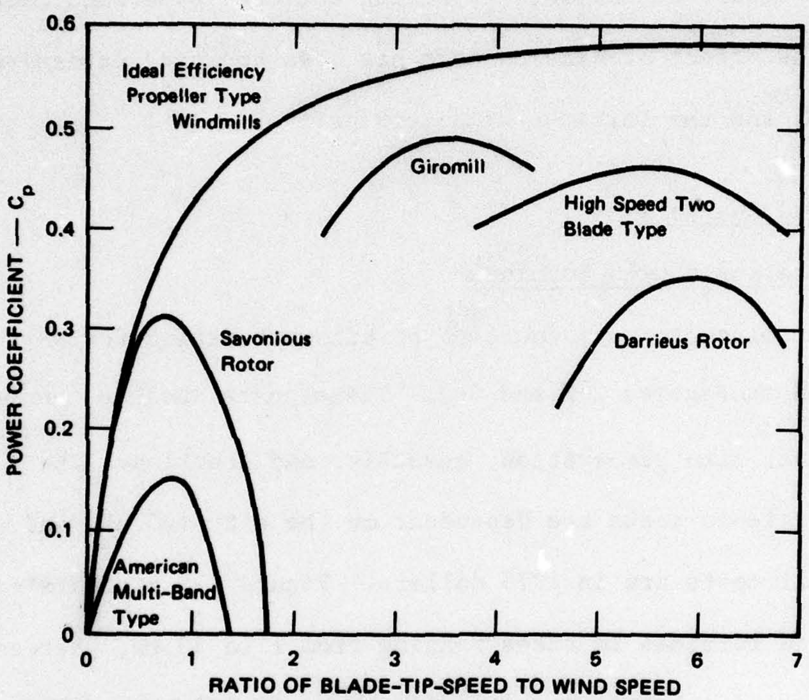
The efficiency of a blade refers to the percentage of energy converted from the available wind energy to rotational energy. A more efficient blade can mean less expensive energy if the blade is not significantly more expensive to manufacture. Balde efficiency (Cp) can be increased by improving the aerodynamics so that the blade tip speed increases (see Figure 2-1). Lift type blades, represented by the giromill, Darrieus, and the high-speed, two blade wind turbine, have higher blade tip speed-to-wind speed ratios, enabling them to extract more power from the wind. Wind turbines that do not take advantage of

Table 2-1

WIND TURBINE CHARACTERISTICS

	Horizontal Axis (HAWT)	Vertical Axis (VAWT)
Direction Dependence	Yaw Mechanism Fixed or Active	Nondirectional
Self-starting	Yes	No
Support	Tall rigid structure	Wires and foundation
Maximum Efficiency	45%	51%
Pitch Control	Optional	Optional
Lift or drag type	Both	Both

Source: SRI International



SOURCE: McDonnell Aircraft Company (1979); F. R. Eldridge (1975)

FIGURE 2-1 POWER COEFFICIENTS OF VARIOUS WIND TURBINES

aerodynamic lifting properties, like the American farm windmill and the Savonius rotor, are called drag type machines. The drag type machines also use more material per swept area, thereby increasing costs. The low efficiency and high cost have eliminated drag type machines from further consideration in this study. The giromill was not included either because extensive development has only recently begun.

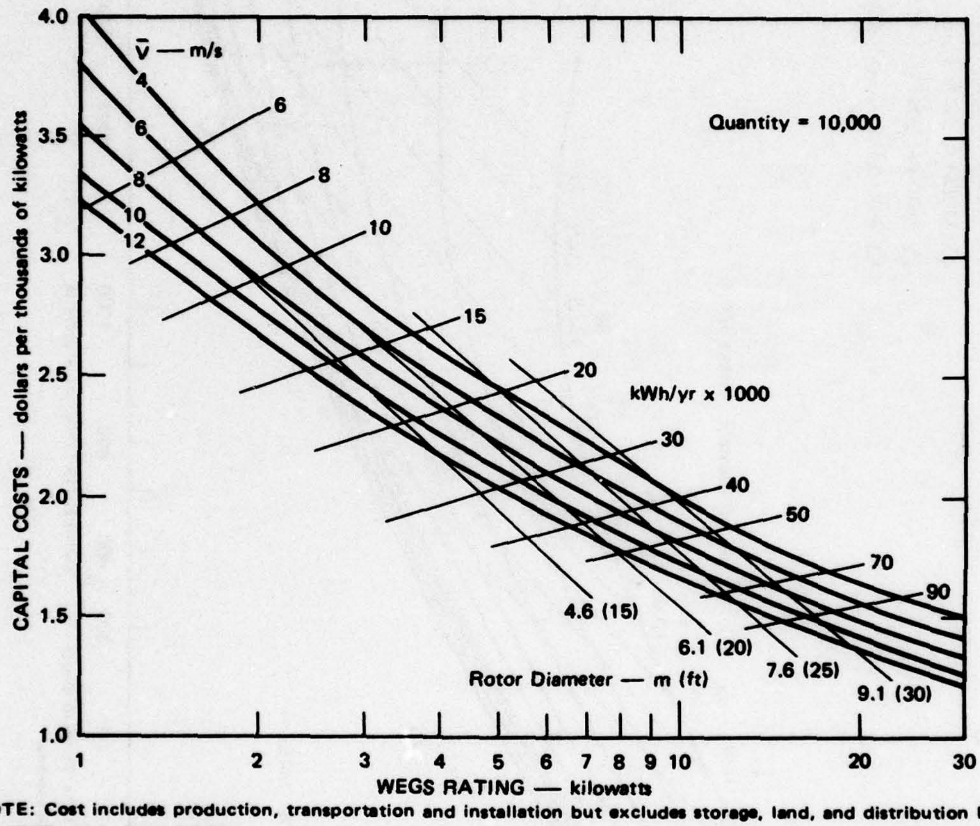
Another important variable affecting the cost of a wind machine is its size. The effect of size on cost has been analyzed extensively for both the HAWT and the Darrieus wind turbine.

Economic Trend Analysis

Horizontal Axis Wind Turbines

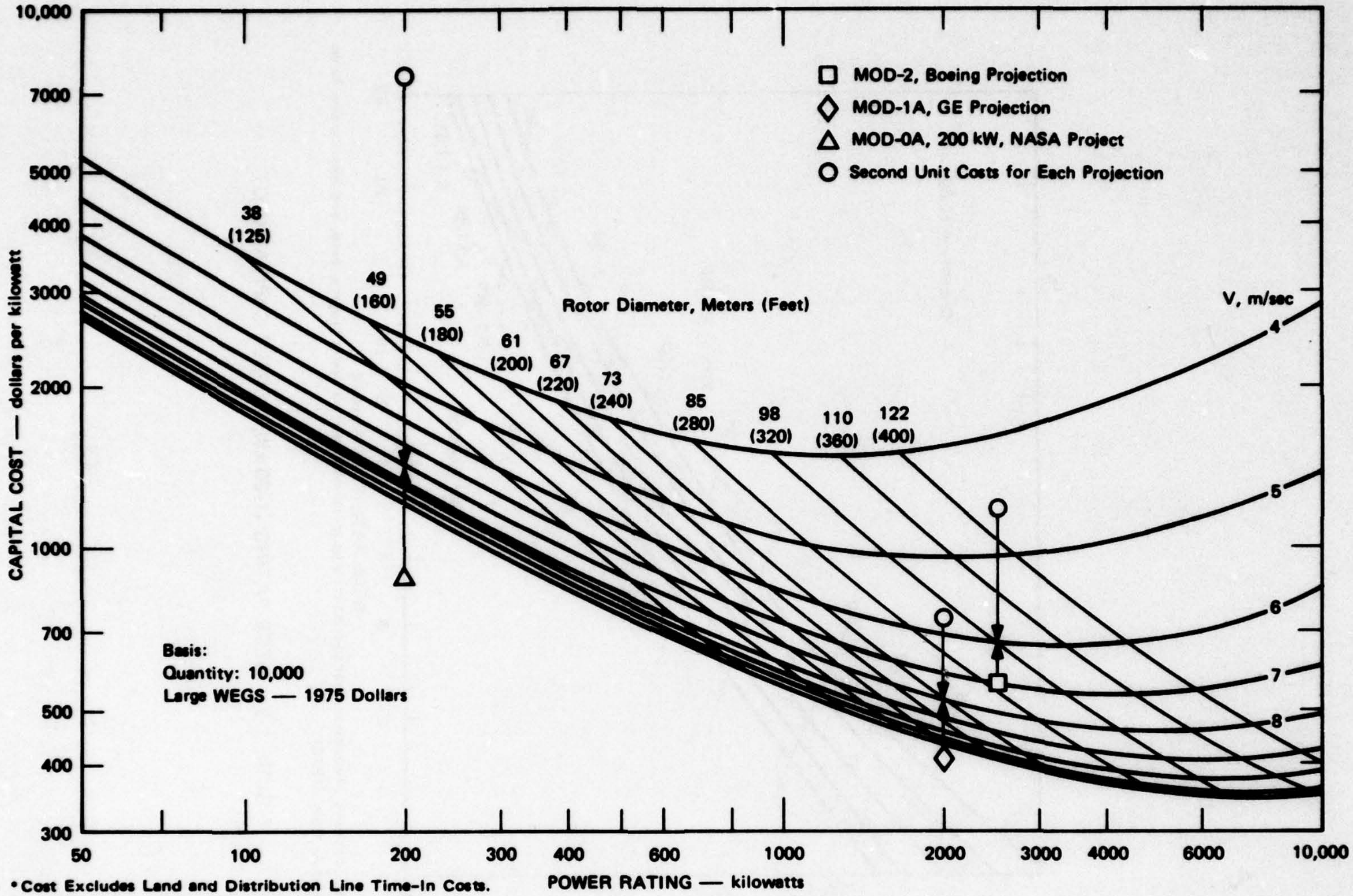
The capital costs as a function of kilowatt rating for HAWT systems are presented in Figures 2-2 and 2-3. These costs include manufacture, transportation, site preparation, assembly, and erection. The land and distribution tie-in costs are dependent on the site and use and are thus excluded. All costs are in 1975 dollars. Figure 2-2 presents cost estimates for wind turbines in sizes ranging from 1 to 30 kW, whereas Figure 2-3 shows costs for larger machines (50 kW to 10,000 kW). These size classifications are useful because different technologies are used for WEGS between 1 kW and 30 kW than for those between 100 kW and 10 MW. The cost estimated of both of these figures are based on production quantities of 10,000 units.

Numerous studies have been made of the economics of mass production of wind machines. As production rates increase, manufacturing efficiency improves, resulting in lower unit costs. These efficiency improvements



NOTE: Cost includes production, transportation and installation but excludes storage, land, and distribution lines.
SOURCE: U.A. Coty (1976)

FIGURE 2-2 WEGS RATING (1-30 kW) VERSUS CAPITAL COST



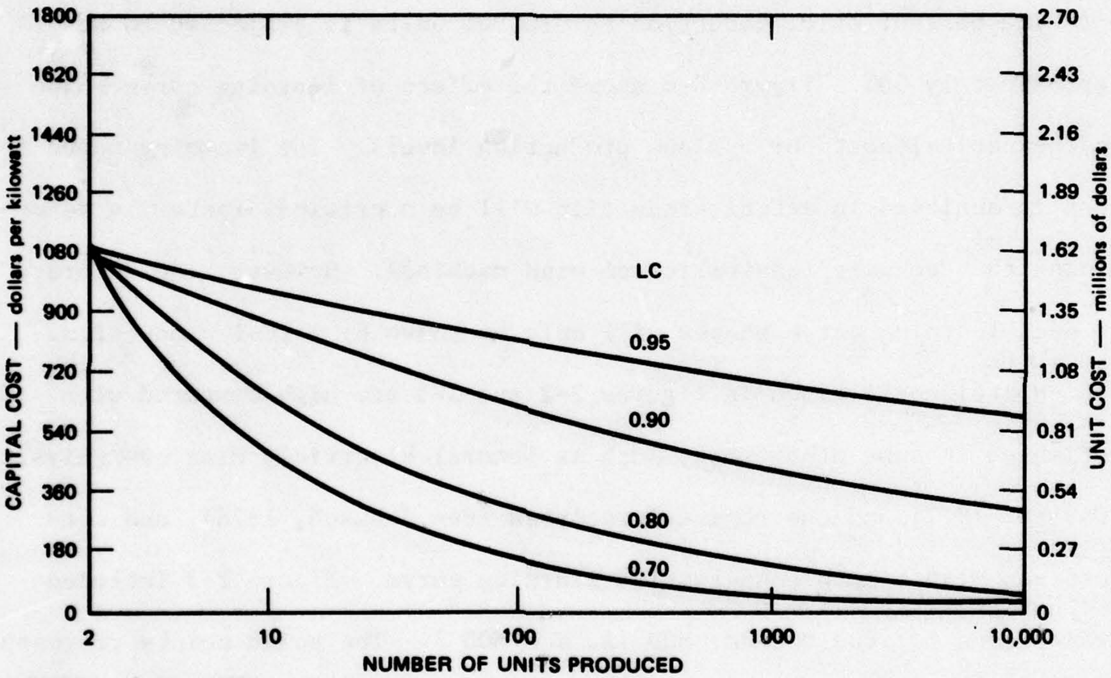
*Cost Excludes Land and Distribution Line Time-In Costs.
SOURCE: U.A. Coty (1976); SRI International

FIGURE 2-3 WEGS RATING AS A FUNCTION OF CAPITAL COST*

are usually presented in terms of "learning curves," which show unit cost as a function of cumulative production. Of course, actual learning curves are not available, so estimates based on judgment and past experience with similar devices must be made (Coty, 1976). Because the WEGS design is a simple structural concept and many of its parts are available off the shelf, the slope of the learning curve for WEGS is likely to be rather flat.

The percent price reduction for 10,000 units is projected to be approximately 50%. Figure 2-4 shows the effect of learning curve shape on the capital cost for various production levels. The learning curve that is achieved in actual production will be a critical factor in determining the economic feasibility of wind machines. However, the accuracy of such learning curve shapes will only be known by actual production. The capital costs given in Figures 2-2 and 2-3 are high compared with estimates in some other work, such as General Electric's Mission Analysis (Garate, 1977) and the regional analyses (see Johnson, 1978), and corresponds with a more conservative learning curve. Figure 2-3 includes projections for the MOD 0A, MOD 1A, and MOD 2. The boxed points represent second-unit costs and the lower points represent one-hundredth-unit costs. The arrowed numbers are the design mean wind speeds for each turbine (in m/sec).

The trends of the cost vs. size curve (Figures 2-2 and 2-3) are of most concern in this analysis. From a purely economic viewpoint, these figures indicate that larger machines are the most desirable. Although these projections do not include utilization factors or availability



SOURCE: Johnson (1978)

FIGURE 2-4 COST IMPROVEMENTS FOR VARIOUS LEARNING CURVES

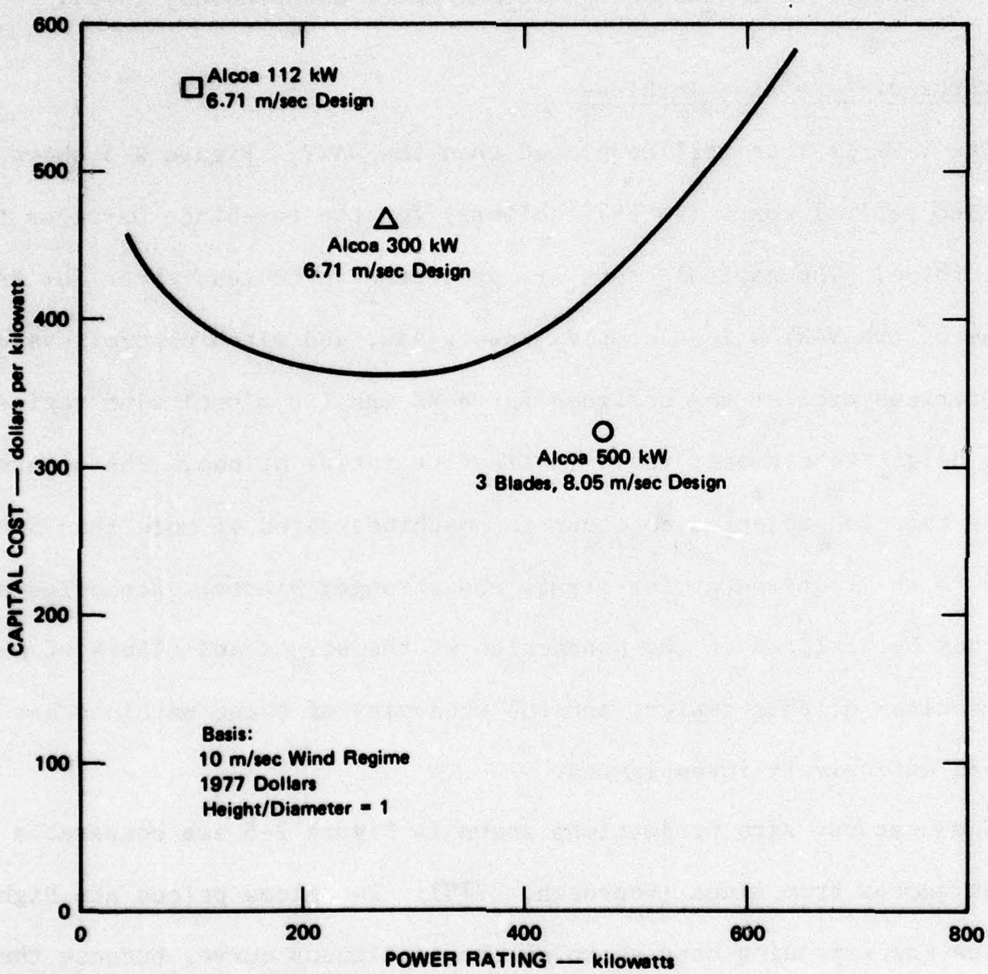
factors, the same trends are projected for cost of electricity using standard utility pricing practices (Coty, 1976).

Maintenance for WEGS has been calculated to be 2 to 3% of the capital cost. This figure can be as much as 70% lower when WEGS are grouped together in a wind energy farm (Ramler and Donovan, 1979).

Vertical Axis Wind Turbines

The VAWT is less well developed than the HAWT. Figure 2-5 shows the projected capital costs (in 1977 dollars) for the two-blade Darrieus type wind turbine. The capital costs are projected to be less those for HAWTs because of the VAWT's less complex tower, yaw, and pitch control systems. This Darrieus machine was designed for a 22 mph (10 m/sec) wind regime with a height to diameter ratio (solidarity ratio) of one. The upturn in cost that is projected to occur for machines rated at more than 300 kW is due to the requirement for struts and stronger blades. Economies of scale may be realized in the production of the struts and blades of megawatt machines of this design, but the economics of these machines has not been extensively investigated.

The cost vs. size projections shown in Figure 2-5 are comparable to current quotes from Alcoa (Vosburgh, 1979). Two Alcoa prices are higher than the corresponding cost shown on the continuous curve, because the two-bladed Alcoa machines (112 kW and 300 kW) are rated at 6.7 m/sec instead of the 10 m/sec used for the curve. At similar speeds, these costs would be closer. The 500-kW Alcoa machine is lower in cost than projected for VAWTs because it incorporates a third blade.



SOURCE: J.C. Yeoman (1978); SRI International

FIGURE 2-5 CAPITAL COSTS OF VERTICAL-AXIS WIND TURBINES

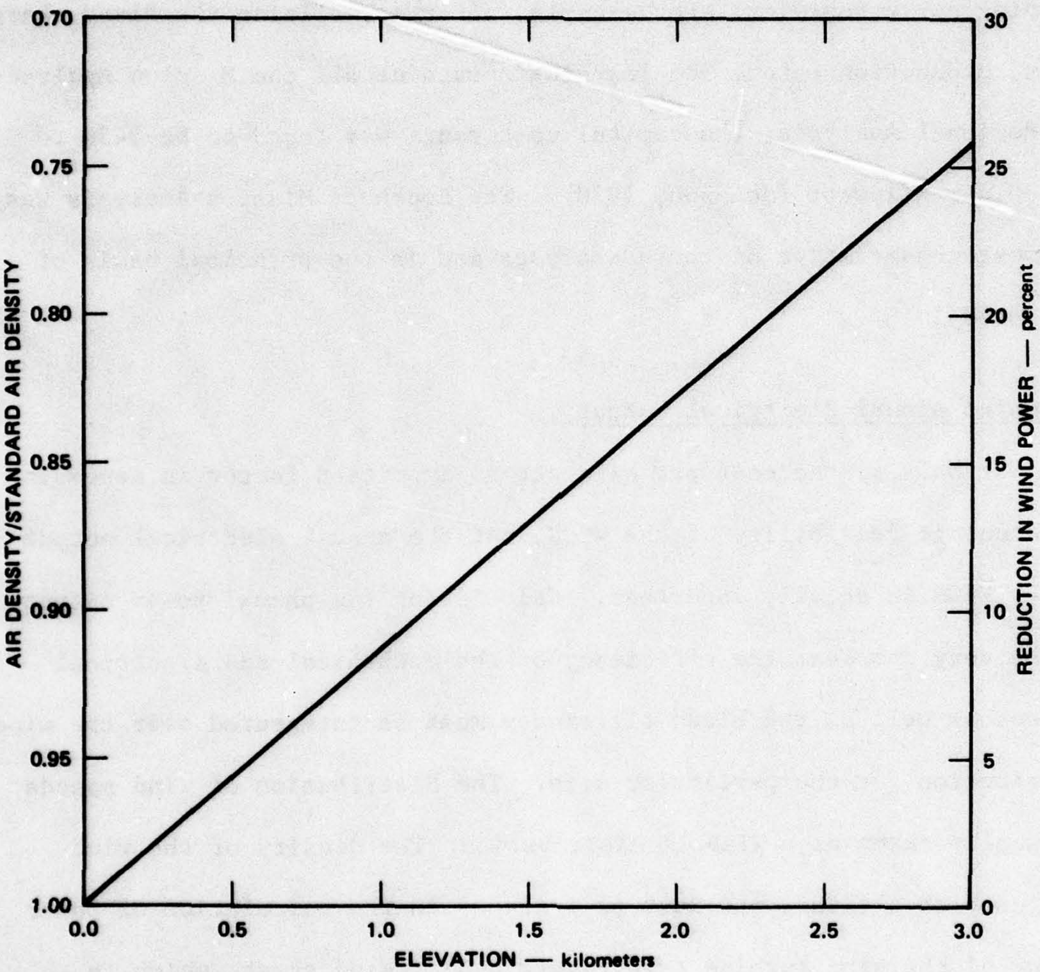
Capital Cost Uncertainty

The capital cost estimates presented here are based on many assumptions that will not be identical for any two machines. These assumptions include production levels, component costs, optimal wind designs, and learning curve behavior. For example, after normalizing the fixed charge rates, production rates, and learning curves of all the Mission Analyses and Regional Analyses, the capital cost range was found to be $430 to $1,130 per kilowatt (Johnson, 1978). The Lockheed Mission Analysis was the most conservative of these analyses and is the principal basis of this study.

Estimated Annual Electrical Output

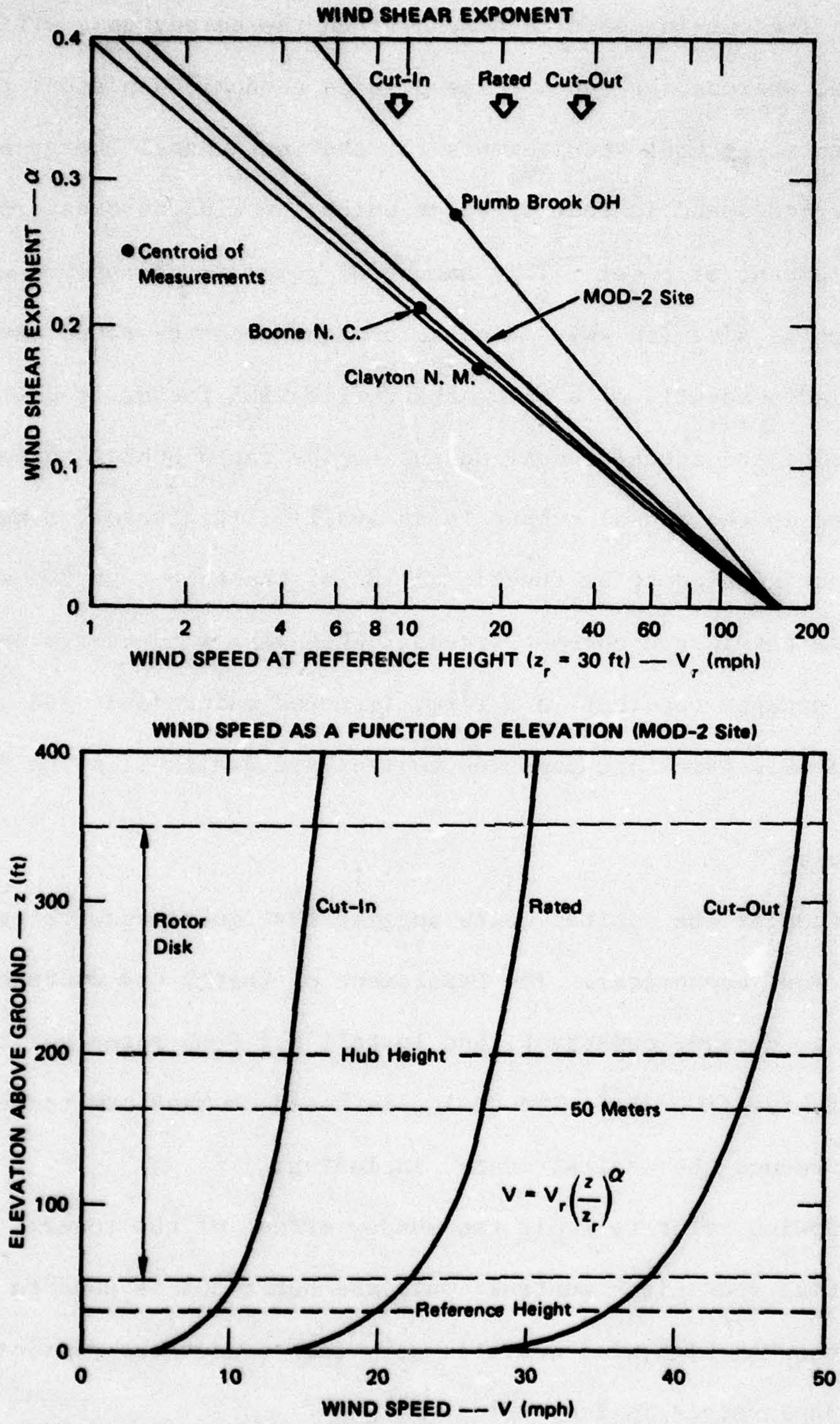
Not only is the cost per kilowatt an important factor in assessing the economic feasibility of the WEGS, but the annual electrical output of the WEGS is equally important. Calculating the annual power output can be very complex; the efficiency of the mechanical and electrical systems as well as the blade efficiency must be integrated over the wind distribution for the particular site. The distribution of wind speeds is usually taken as a Wiebull distribution. The density of the wind changes with altitude and must be included in the calculation of power output of the wind turbine (see Figure 2-6). Wind shear, which is dependent on height above ground, must also be included in the analysis. The standard practice of using an average hub wind speed, as determined by a wind shear model, was used in this analysis (see Figure 2-7).

Three key wind speeds also set the limits of power production; they are the cut-in speed, the cut-out speed, and the rated speed, as seen in



SOURCE: Yeoman (1978)

FIGURE 2-6 EFFECT OF ELEVATION IN WINDSTREAM POWER AT CONSTANT WIND SPEED



NOTE: Cut-in, rated, and cut-out wind speeds are shown for sea-level STD conditions.
SOURCE: Boeing Engineering Company (1978)

FIGURE 2-7 WIND SHEAR BEHAVIOR

Figure 2-8. The cut-in speed is dependent on the aerodynamic efficiencies of the blade, whereas the cut-out speed is an economic decision, trading off increased structural requirements for the incremental energy available. The rated speed is that speed at which the wind turbine produces its maximum amount of power. This amount of power is commonly used to describe machine size (in kW). Because a machine can be rated at any wind speed independently of a site, the utilization factor is calculated as the ratio of the actual annual output to the rated annual output.

Included in the annual output is an availability factor; single plants are anticipated to be functional 90% of the time that the wind is within the cut-in and cut-out speeds. When many wind energy generating systems are grouped together in a farm, improved maintenance and more readily available parts are expected to increase availability to 96%.

MOD 2 Selection

The trends of the capital costs suggest that multimegawatt machines will be the most economical. The Department of Energy has contracted with Boeing to design, construct, and install a 2.5-MW rated horizontal axis wind machine (MOD 2).* The design is based on many new concepts intended to reduce the capital costs, including:

- An upwind rotor to avoid the shadow effect of the tower.
- Partial span pitch control; only the outer 30% is used to feather in high wind conditions, which reduces the physical loads involved in feathering.

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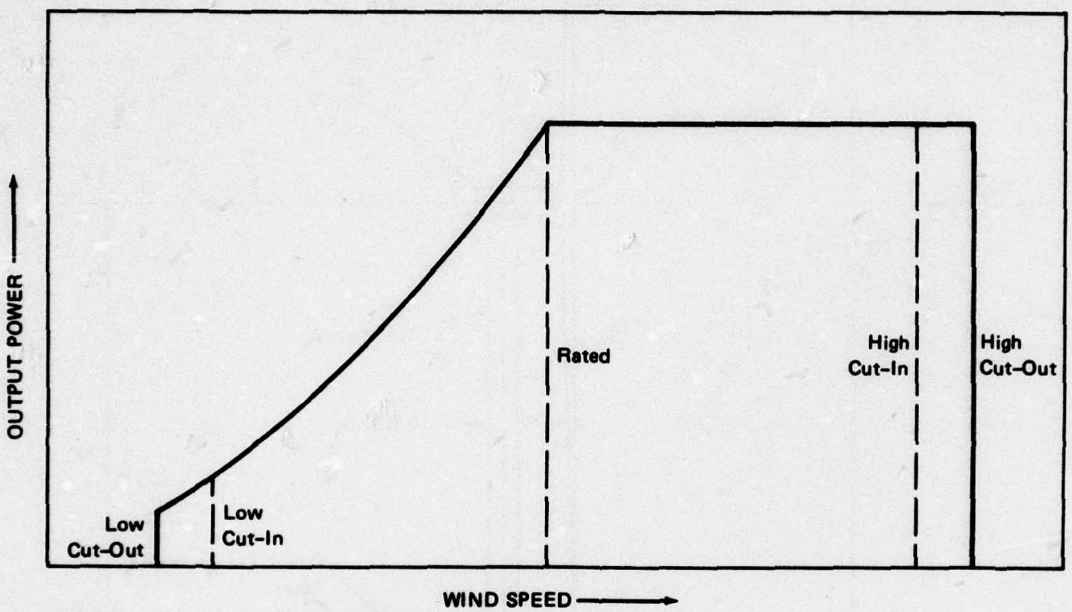
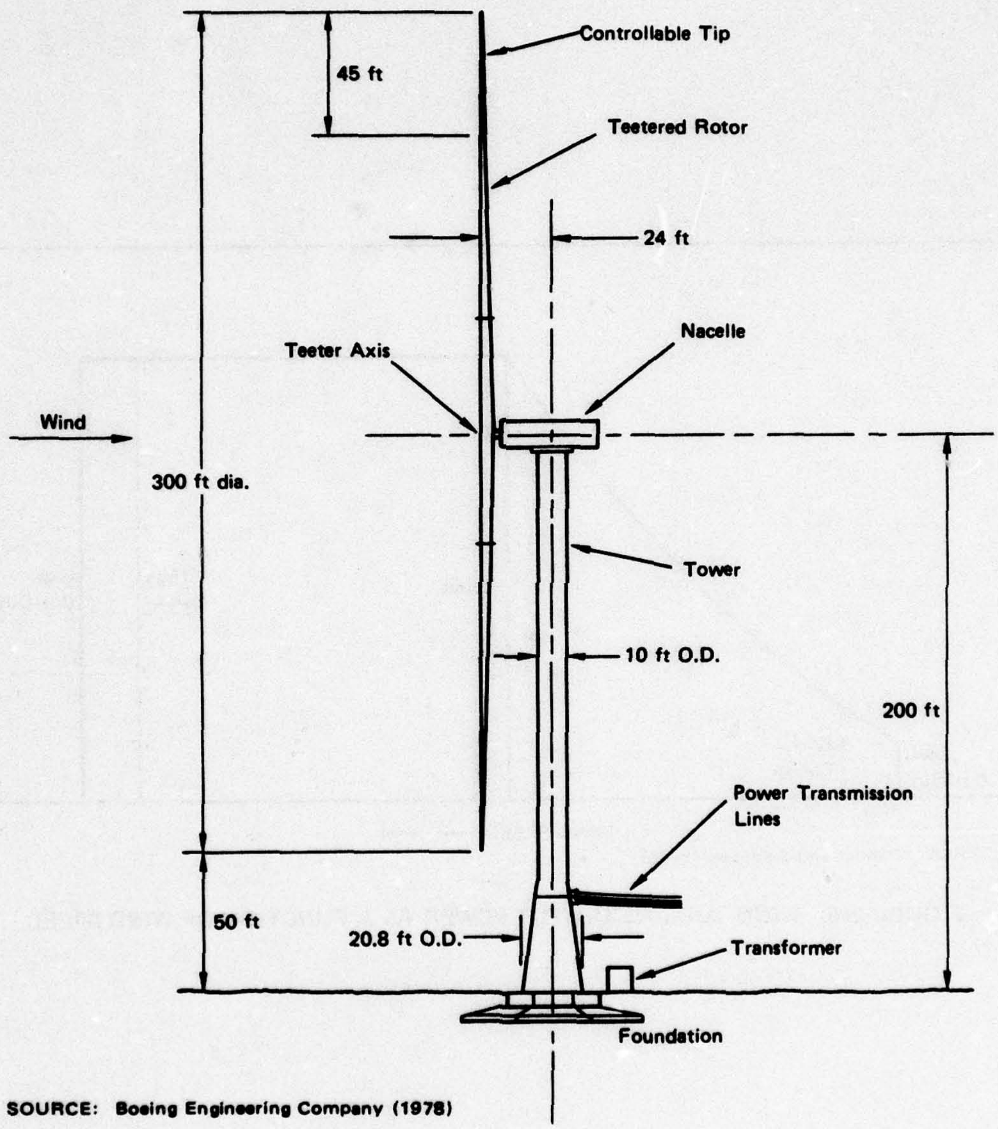
*Figure 2-9 gives the dimensions and configuration of MOD 2, which is to have fully automated operation by mid-1980.



SOURCE: Ramler and Donovan (1979)

FIGURE 2-8 WIND TURBINE OUTPUT POWER AS A FUNCTION OF WIND SPEED



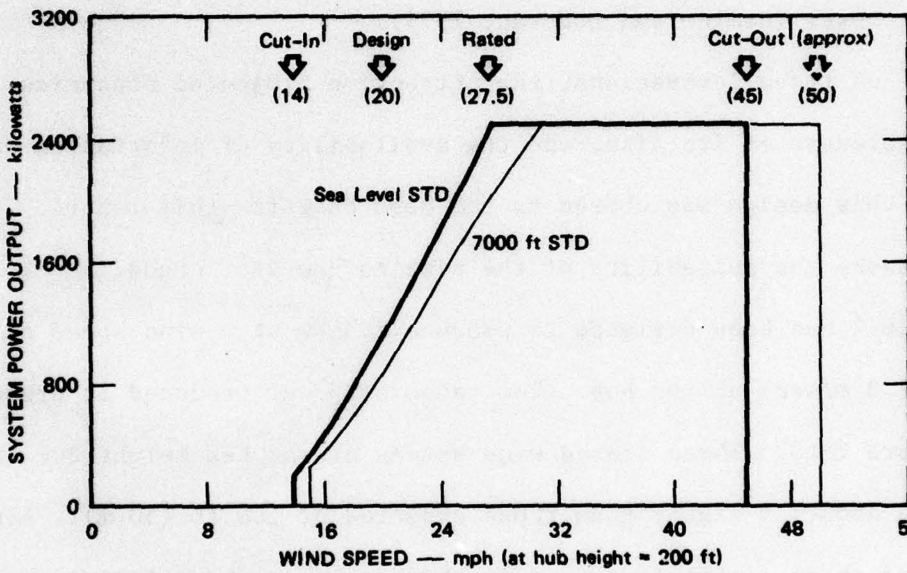
SOURCE: Boeing Engineering Company (1978)

FIGURE 2-9 MOD 2 CONFIGURATION

- An operating speed of 17.5-rpm, half that of MOD 1, which will reduce the stress loads and thus the weight.
- A teeter mechanism that allows 5° of teeter. Teetering reduces the stresses on the hub from gusts and wind shear imbalances.
- A planetary gear box, lighter and more efficient than the parallel gear box.
- A flexible tower, costing less than the open truss tower (Ramler and Donovan, 1979).

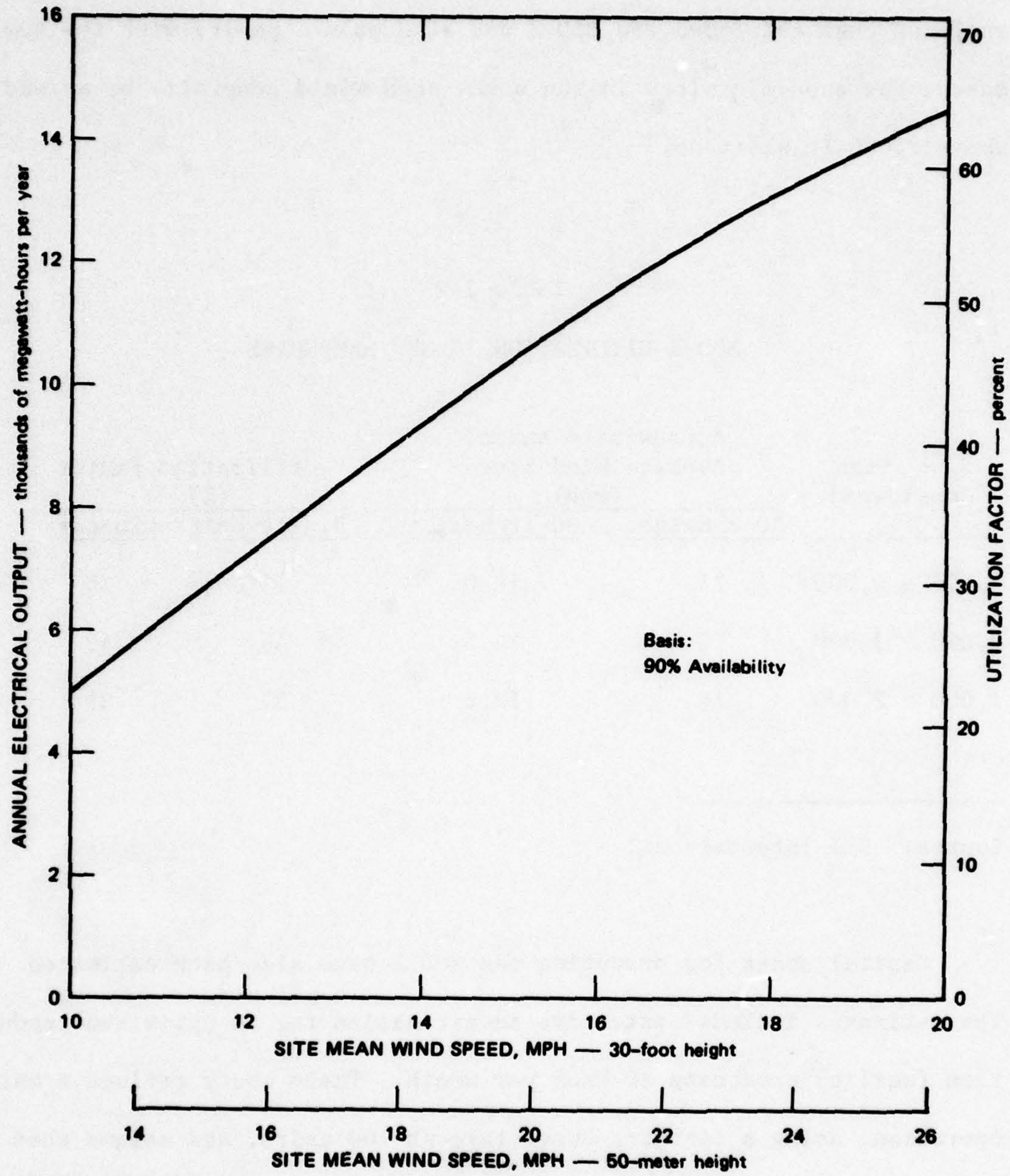
Because of these innovations, the attractive projected economics, the reasonableness of its size, and the availability of information on the MOD 2, this design was chosen as the base case for this report. Section 6 discusses the suitability of the size to the user needs.

MOD 2 has been designed to produce 2.5 MW at a wind speed of 27.5 mph (12.3 m/sec) at the hub. The range of power produced is presented in Figure 2-10. These stated wind speeds are at hub height 200 ft (65.6 m) and are about 3% higher than those expected at 164 ft (50 m). Although the wind shear coefficient used in this analysis approximates rough terrain, each site has its own characteristics. The MOD 2 also has a low cut-out speed, 5.8 m/sec (13 mph), and a high cut-in speed, 18.9 m/sec (42 mph), to reduce the start-up and shut-down stress associated with unstable winds. The power output produced by the MOD 2 has been analyzed extensively. Figure 2-11 presents the annual electrical output at various mean wind speeds. Table 2-2 also presents the specific utilization factors for the average wind speeds 164 ft (50 m) above the ground at various elevations. These figures incorporate a 90% availability



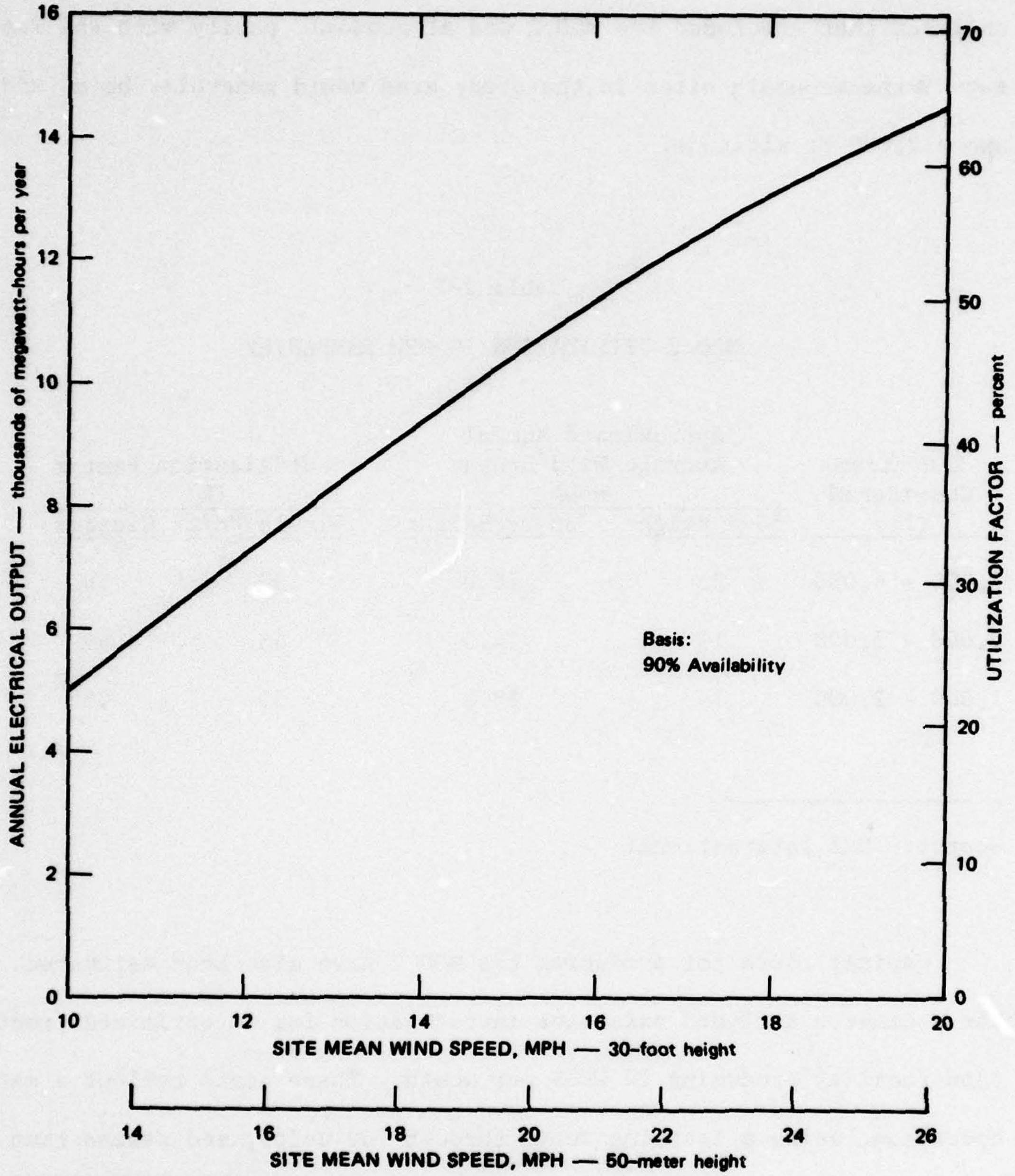
SOURCE: Boeing Engineering Company (1978)

FIGURE 2-10 MOD 2 POWER OUTPUT AS A FUNCTION OF WIND SPEED



SOURCE: Ramler and Donovan (1979); SRI International

FIGURE 2-11 MOD 2 ANNUAL OUTPUT AND UTILIZATION FACTORS



SOURCE: Ramler and Donovan (1979); SRI International

FIGURE 2-11 MOD 2 ANNUAL OUTPUT AND UTILIZATION FACTORS

for the single unit and a 96% availability for the cluster installation. Because 50% utilization is assumed in the Section 3 base case economic analyses that concluded the MOD 2 was at economic parity with the fuel saved, the economic sites in the study area would generally be at and above 2,000 ft altitude.

Table 2-2

MOD 2 UTILIZATION IN NEW HAMPSHIRE

Elevation Considered (ft)	Approximate Annual Average Wind Speed (mph)		Utilization Factor (%)	
	50-m Height	30-ft Height	Single Unit	Cluster
3,000 - 4,000	21	16.0	53	56
2,000 - 3,000	19	14.5	46	49
1,000 - 2,000	16	12.2	33	35

Source: SRI International

Capital costs for producing the MOD 2 have also been estimated. The estimates included extensive investigation for an optimized production facility producing 20 WEGS per month. These costs reflect a mature operation, using a learning curve through 100 units, and assume that initial start-up problems have been resolved. Construction and transportation costs were based on job estimates for a 25-unit wind farm with a separation of 0.5 to 0.75 mi (0.8 to 1.2 km) between turbines (8.8 to 12 rotor diameters). One substation, not included in the cost estimates,

was allotted for a cluster of four to five WEGS. This substation would receive 13.8 kV, three-phase current from a transformer used to step up the power coming from the MOD 2 synchronous generator. The costs are summarized in Table 2-3; a 10% fee is also included. The total capital cost escalated to 1979 dollars for a single unit in a 25-unit farm is $2,041,000 (Boeing, 1978). The capital cost of the second prototype, which does not include mass production or learning curve reductions, is estimated by Boeing Engineering Company to be $4,010,000 (JBF Scientific Corp., 1977). Neither estimate includes the cost of land, intracluster costs, contingency allowances for funds during construction, or tie-in costs. Capital cost projections and utilization factors are summarized in Table 2-4. Estimates for the transmission and protection systems have been made for a multitude of site conditions by Cornell Univesity (Teshome and Yehasakul, 1979). From these figures, approximately $100/kW would be required for complete tie-in of 25 MOD 2 WEGS along a ridge.

Operation and Maintenance

Operation and maintenance costs are highly dependent on whether the installation involves a single unit or a cluster of units. A cluster permits labor costs to be spread over several units, thereby lowering costs. An economic trade-off analysis concluded that a full supply of spare parts would be economical for a cluster of 25 WEGS (Boeing, 1978).

The total operation and maintenance cost is also presented in Table 2-5. Failure mode analysis was performed for each component; failure rates were calculated and included in costs. Both scheduled and unscheduled repairs, as well as crew availability, were included. A

Table 2-3

COST SUMMARY FOR 25-UNIT CLUSTER
(100th Production Unit, 1979 Dollars)

	Turnkey Account	Cost	% of Total
1.0	Site preparation	$ 193,000	9.5
2.0	Transportation	34,000	1.7
3.0	Erection	163,000	8.0
4.0	Rotor	391,000	19.2
5.0	Drive train	451,000	22.1
6.0	Nacelle	219,000	10.7
7.0	Tower	322,000	15.8
8.0	Initial spares	41,000	2.0
8.A	Nonrecurring (facility)	41,000	2.0
9.0	Total initial cost	1,855,000	
	Fee (10%)	186,000	9.1
	Total turnkey	2,041,000	100.0
10.0	Annual operations and maintenance	$ 17,900	
10.A	Annual operations and maintenance (single unit)	$ 57,800	

Source: Boeing Engineering Company (1978); escalated to 1979 dollars by SRI International

Table 2-4

MOD 2 ECONOMIC PARAMETERS*
(1979 Dollars)

2.5-MW MOD 2	Installed Cost ($ Million)	$/kW	O&M Dollar Costs	Utilization Factor (%) at 50-m Height 21 mph	19 mph	16 mph	Spacing Factor
Second Unit Prototype	4.01	$1,610	$57,800	53	46	33	---
Single Unit in Cluster	2.04	816	17,900	56	49	35	4 units/mi^2

*Excludes intracluster, contingency, and tie-in costs.

Source: SRI International

two-shift, two-man crew, 6 days per week was the basis for labor costs. Most repairs will take place in the tower-mounted nacelle containing the transmission, generator, and yaw and pitch mechanisms using off-the-shelf maintenance and handling equipment. Blade inspection will require special rigging. The operating status of each unit can be determined from the substation. The MOD 2 is also equipped with an automatic fire detection and a self-extinguishing system as well as standard emergency equipment (Ramler and Donovan, 1979).

Reliability

The design specification for the MOD 2 indicates the reliability for a site (see Table 2-5). In the Northeast U.S. environment, icing can be a major problem. Areas where more than 2 in. (5 cm) of ice can be

Table 2-5

MOD 2 DESIGN ENVIRONMENT

	Transportation	Storage Installation	Operational
Duration	3 weeks	3 months	30 years (2104 hr/y standby) (6662 hr/y pwr opn)
Wind	Negligible	Negligible	120 mph at 30 ft reference elevation
Shock	Rail: 20G peak Truck:3G peak	Negligible	See: seismic
Vibration	3G	Negligible	As induced by the rotor, high speed shaft Gearbox
Temperature	Same as operational	Same as operational	-40°F (-40°C) to 120°F (48.9°C) ambient air
Solar radiation	Same as operational	Same as operational	363 BTU/ft^2/hr, 4 hr/d, 6 mo/y
Lightning	Negligible	Negligible	Variable current profile over 360 ms, with 200 kA peak current
Rain	Same as operational	Same as operational	4 in/h
Hail	1.0 in diameter, 50 lb/ft^3 132 ft/sec velocity (applicable to shipping containers)	1.0 *in diameter*, 50 *lb/ft^3* 66.6 ft/sec velocity (applicable to storage containers)	1.0 *in diameter*, 50 lb/ft^3, 66.6 ft/sec velocity (horizontal and vertical surfaces)
Ice (glaze)	2.0 in thickness, 60 lb/ft^3 (applicable to shipping containers)	2.0 in thickness, 60 lb/ft^3 (applicable to storage containers)	2.0 in thickness, 60 lb/ft^3 (on all external surfaces)
Snow	41 lb/ft^2 (shipping containers)	41 lb/ft^2 (storage containers)	Blade: 21 lb/ft^2 Nacelle: 41 lb/ft^2
Humidity, sand/ dust, salt spray, fungus	Same as operational	Same as operational	Exposure equivalent to MIL-STD-210B for exposed or sheltered ground equipment, as applicable
Fauna	Exposure to insects	Same as transportation	Same as transportation plus 4 lb birds at 35 mph for stationary surfaces above 150 ft
Noise	Negligible	Negligible	Negligible
Seismic	Negligible	Negligible	Site specific
Altitude	Same as operational	Same as operational	Sea level to 7,000 f

Source: D.H. Reilly (1979)

expected should not be considered. Ice that does form during operation may be shed by the flexing of the blade. However, operating personnel or the public are not likely to be endangered, because icing usually occurs during severe weather conditions, which reduces the chance for public exposure. Icing detectors have been used successfully on MOD OA, but the system can start with ice on the blades. If an unstable condition occurs during operation (i.e., large pieces of ice falling off of a single blade), the stability detector will feather the rotor and apply the brake.

The separation between WEGS also affects the reliability of power output. A separation of 0.5 mi to 0.75 mi (0.8 to 1.2 km) staggered with respect to the prevailing winds is recommended for the MOD 2 (Ramler and Donovan, 1979). However, in calculating the number of MOD 2 units per square mile of potential sites, the lower separation distance, 0.5 mi, was used in this analysis.

Because the rough terrain associated with most New Hampshire sites will be a more significant factor in the air flow than the proximity of other wind turbines will be, the estimate of the total energy available for New Hampshire was based on an allotment of four MOD 2 units per square mile of good site area. The total estimated wind energy available in New Hampshire for the estimated 1,626 machines is 14.3×10^6 MWh per year. Table 2-6 classifies the potential wind energy by elevation and sector.

The corresponding power output of the WEGS would be 4,065 MW when operating at rated capacity. At present, 400 MW (10% of the intermediate-service generating capacity) is the maximum amount of wind energy that

Table 2-6

SUMMARY OF THE POTENTIAL ANNUAL ENERGY RESOURCE USING MOD 2
(MWh)

Altitude Range (feet)	Sector 1	Sector 2	Sector 3	Sector 4	Total Energy Potential
1000 - 2000	1,214,000	660,000	1,160,000	611,000	3,645,000
2000 - 3000	2,630,000	921,000	2,450,000	2,860,000	8,861,000
3000 - 4000	170,000	138,000	212,000	954,000	1,474,000
4000 - 5000	0	0	0	254,000	254,000
5000 - 6000	0	0	0	68,700	68,700
TOTAL	4,014,000	1,719,000	3,822,000	4,747,700	14,302,700 (90% Availability)

can be absorbed by the regional power grid (NEPOOL) without encountering problems of dispatching reliability.

Fracture Hazard

The major safety hazard that a wind turbine presents to the public is the possibility of a blade being thrown. This can occur if the rotor is turned at a speed above its design speed. To prevent it, two independent protection systems have been designed into the MOD 2. Both are designed to feather the blades to zero torque in excessive winds and then apply the brake. Feathering and braking also happen if a major failure in the system occurs. The power for the shut down is stored in hydraulic accumulators and locks are provided to hold the tips in the feathered position when the hydraulic system is depressurized. The system is also equipped with a stability detection device that activates the shutdown procedure if an instability is detected. The MOD 2 machine is designed to withstand 120 mph (193 km/hr) constant winds. Buckling may occur at significantly higher wind speed, but in those conditions, the public is not likely to be near a remote wind turbine. All components have been designed with standard engineering safety considerations, including:

- Fatigue analysis
- Failure mode analysis
- "Safe life" concepts
- "Fail safe" concepts; that is, if parts fail, they are designed to do so in a manner that is not injurious to human life or catastrophic to the WEGS (Boeing, 1978).

NASA/Lewis Research Center has played an integral part in the design and safety assessment of federally supported wind machines.

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3. ECONOMIC CONSIDERATIONS

Summary and Conclusions

The fluid state of cost projections for WEGS and the rapid progress of research and development on the technology led SRI to avoid using a single wind machine cost estimate for this study. The possibility of nonutility ownership of WEGS led SRI to examine a variety of financing alternatives that result in fixed charge rates different from the conventional 17%/year that is the common rate for utilities. Because the generating capacity utilization of wind machines depends on local wind conditions, SRI estimated the variations in the cost of electricity that might accompany variations in the amount of power that could be obtained from WEGS under different wind and weather conditions. SRI has analyzed WEGS economics by determining the relationship of the cost of electricity to investment cost, operating and maintenance costs, fixed charge rates, and annual utilization of capacity. These estimates should supply the necessary data for making individual decisions concerning the economic feasibility of the purchase and installation of WEGS at specific sites.

To determine the economic feasibility of WEGS, it is also necessary to compare the costs of WEGS electricity with those of electricity from conventional, and competing, generators. SRI has assembled representative cost data for these other generators to facilitate comparisons and provide a basis for decisions. A single-point comparison leads to the conclusion that WEGS can be competitive with alternative equipment under certain circumstances.

Comparison of Electricity Generating Costs

Determining the cost of electricity requires consideration of the following elements: the generating unit investment; the generating unit capacity; the fixed charge rate* that is used to obtain a return on the investment; the degree of utilization of the capacity of the unit; the operating and maintenance costs for the unit; the cost of fuel for the generator; and the efficiency with which the unit converts its consumed fuel to electricity. Fuel and fuel conversion efficiency are not applicable electricity cost elements for the renewable energy sources such as hydropower, solar photovoltaic power, and wind.

The present WEGS designs are new enough and few enough to make it very difficult to obtain credible investment cost estimates, but a rough estimate is that the large machines will cost something less than $2,000/kW of installed capacity (1979 dollars). The most recent Boeing estimate for 100th unit cost of the 2.5-MW MOD 2 is $816/kW (1979 dollars).

The operating and maintenance (O&M) costs for WEGS will be difficult to estimate until users have more experience with these machines in actual service at a variety of sites. Published estimates of the annual costs have generally been 1-2% of the investment cost. SRI chose 5% as an upper limit for its parametric analyses.

The annual fixed charge rate currently used by many utilities as their operating target is 17%. SRI has chosen a limit of 50%, which not only satisfies the utility's requirements, but also covers the rates that might be sought by high-risk industrial investors.

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*The method of deriving the fixed charge rates used in SRI's economic analysis is detailed in Section 4, Institutional Considerations.

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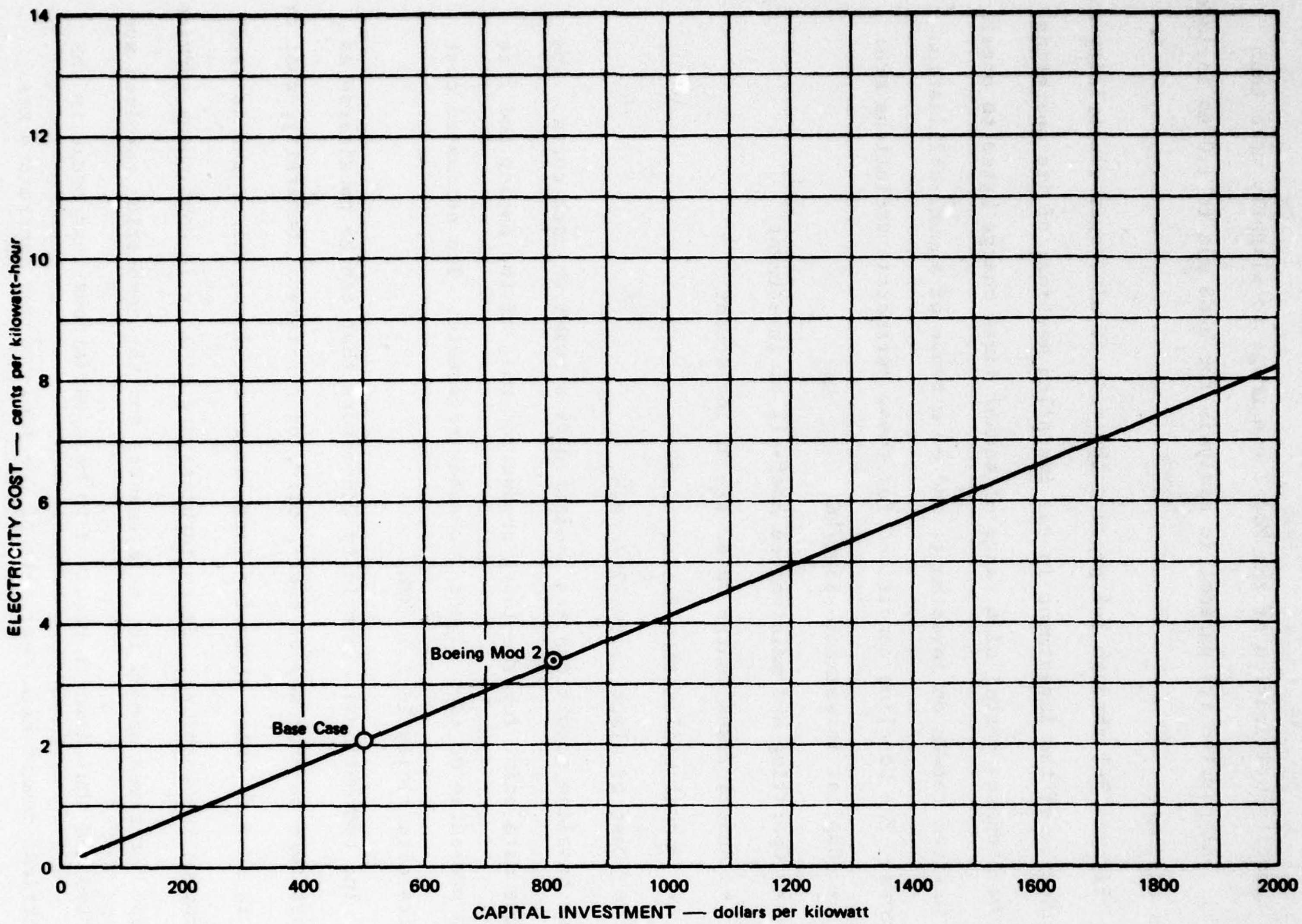
Boeing estimates that, under favorable persistent wind conditions, the capacity utilization of the Mod 2 can range to slightly more than 0.65. SRI carried its parametric analysis for WEGS out to 1.0 to include this estimate.

Figures 3-1 through 3-4 present the cost of windpower electricity as a function of the investment in the installed machine; of its operating and maintenance costs; of a range of annual fixed charge rates to obtain the desired return on investment; and of a range of annual utilization factors. The baseline conditions for these parametric variations are:

- Capital investment--$500/kW
- Operating and maintenance cost--1% of investment
- Annual fixed charge rate, 17% of investment
- Annual utilization factor--0.50
- Cost of electricity--2.1¢/kWh.

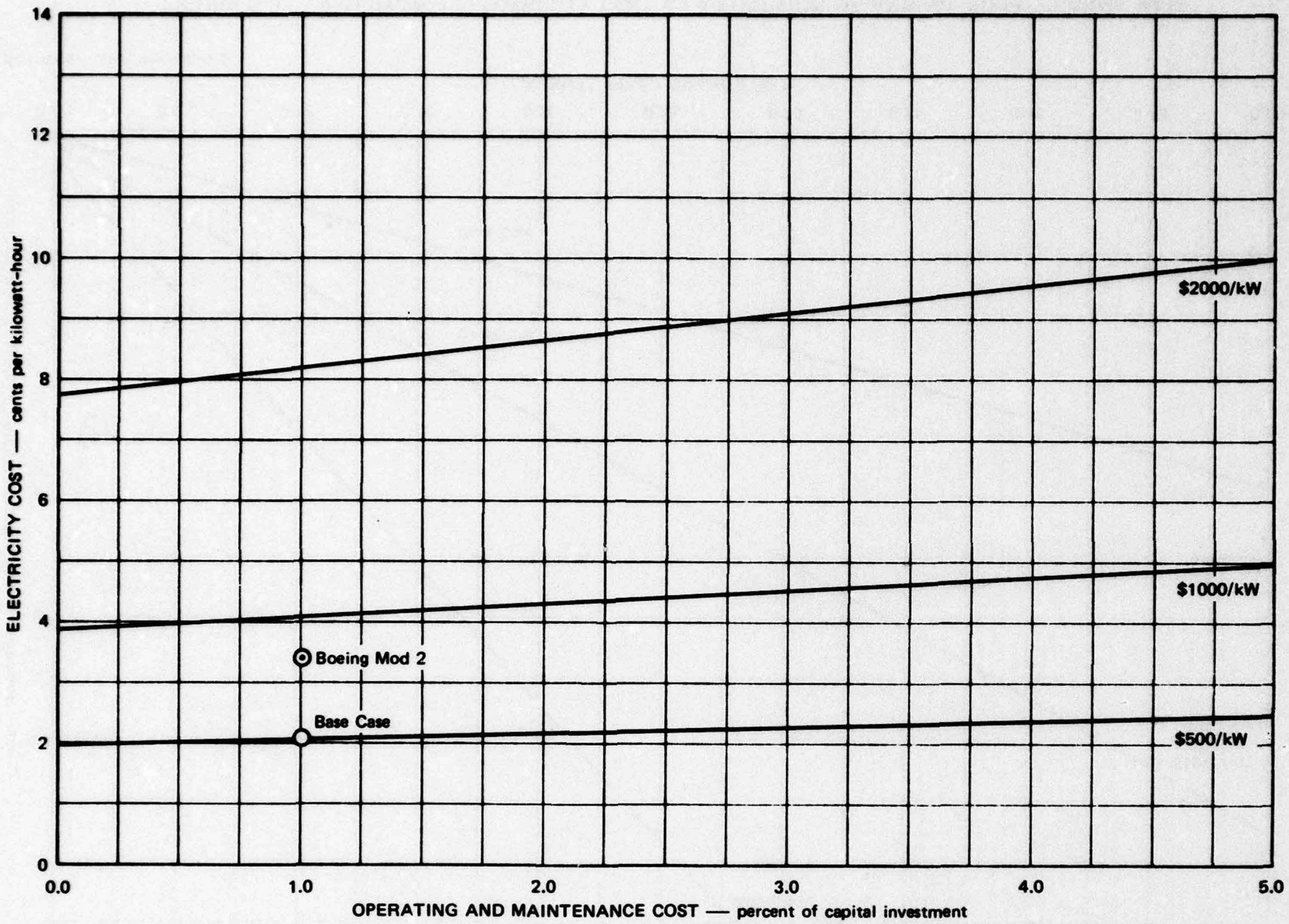
These baseline conditions are indicated by a point on each curve. The single data point for the 100th production unit of the Boeing Mod 2 is also presented on each figure for ready reference. The estimated cost of its electricity is 3.4¢/kWh.

The conventional electricity generators that can be considered as competitors to WEGS may be coal-, oil-, or gas-fired. Generally, coal or oil is used to raise steam for large steam turbines; oil or gas is used in combustion turbines. Steam turbines are usually in continuous service except for times needed for maintenance, and the combustion turbines are started and shut down as required to meet variations that occur in the electrical demand each day. All of the fuel-burning generators are



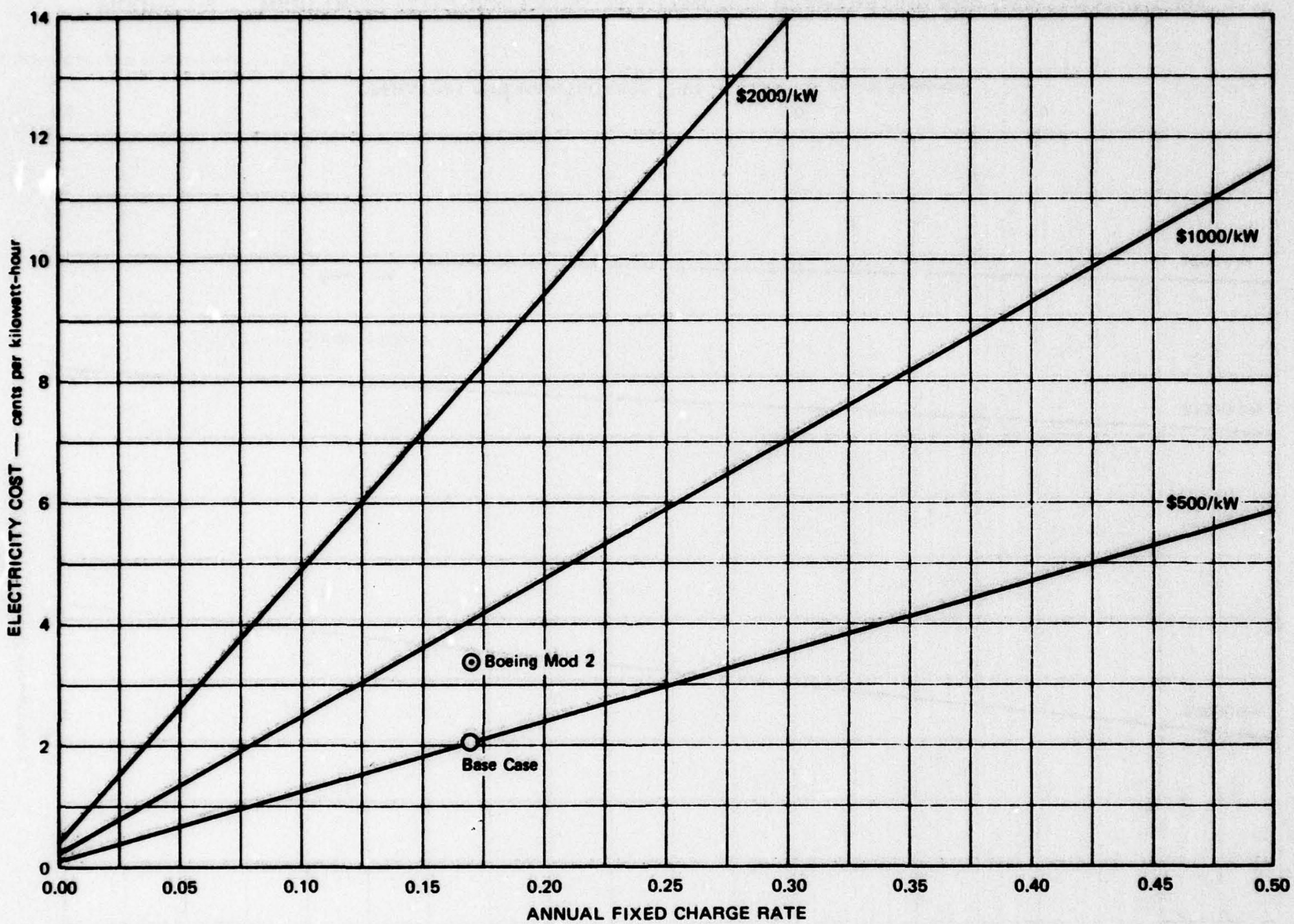
SOURCE: SRI International

FIGURE 3-1 WINDPOWER ELECTRICITY COST AS A FUNCTION OF CAPITAL INVESTMENT



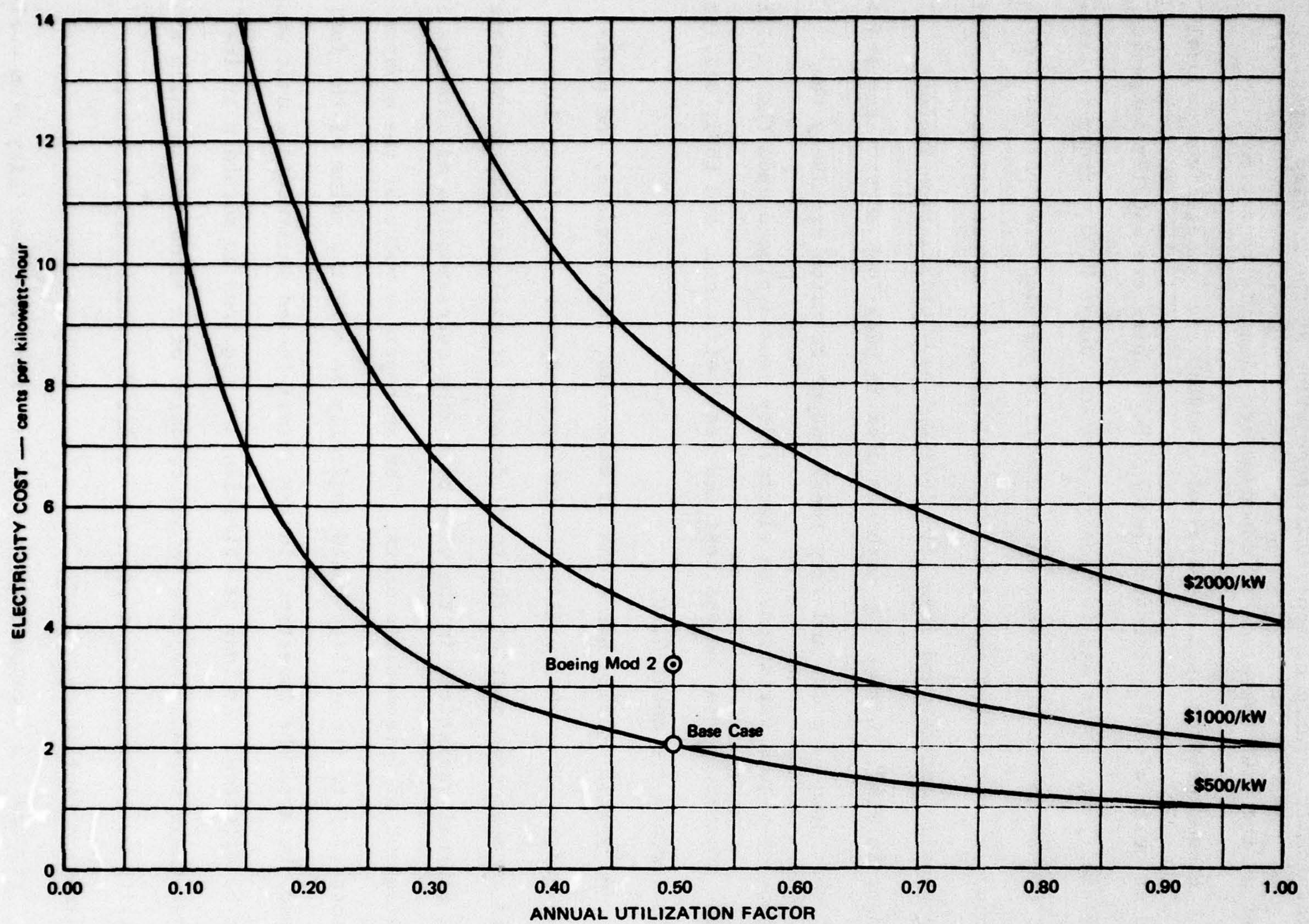
SOURCE: SRI International

FIGURE 3-2 WINDPOWER ELECTRICITY COST AS A FUNCTION OF OPERATING AND MAINTENANCE COST



SOURCE: SRI International

FIGURE 3-3 WINDPOWER ELECTRICITY COST AS A FUNCTION OF ANNUAL FIXED CHARGE RATE



SOURCE: SRI International

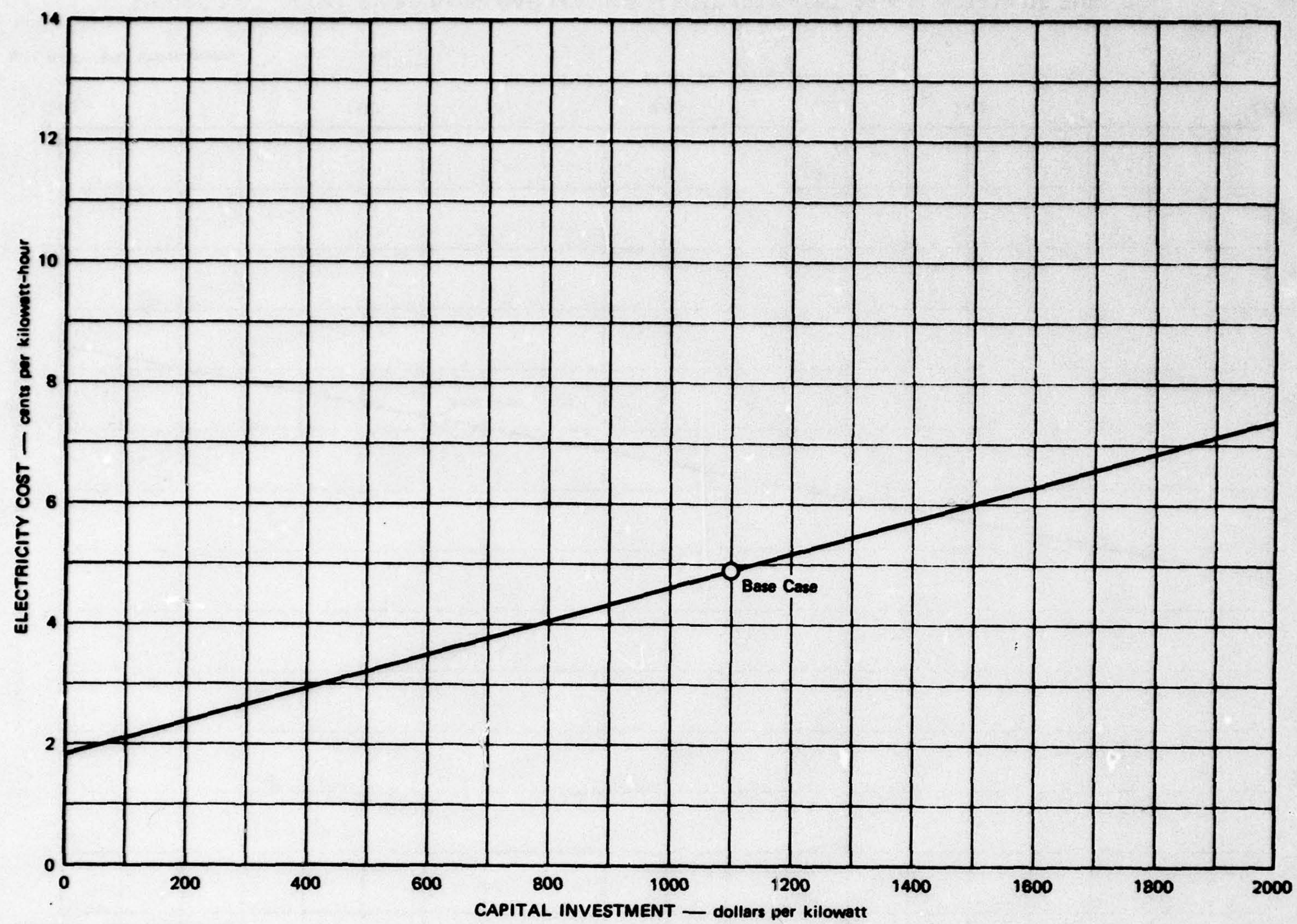
FIGURE 3-4 WINDPOWER ELECTRICITY COSTS AS A FUNCTION OF ANNUAL CAPACITY FACTOR

mechanically capable of continuous generation at their rated capacity, whereas the WEGS operation is dependent on climatic conditions.

Steam turbines used in base-load service are operated continuously and at quite a constant output level. Such units are usually large and efficient, and their utilization factors are about 0.70. Steam turbines and combustion turbines used in intermediate service are operated continuously, but with frequent hourly variations in output. These generators are usually smaller and less efficient and have utilization factors closer to 0.40. Combustion turbines used in peak-load service are started and shut down each day and vary their output to match precisely the minute-by-minute variations in electricity demand placed upon the utility. These generators are the smallest and least efficient, and their utilization factors are about 0.20.

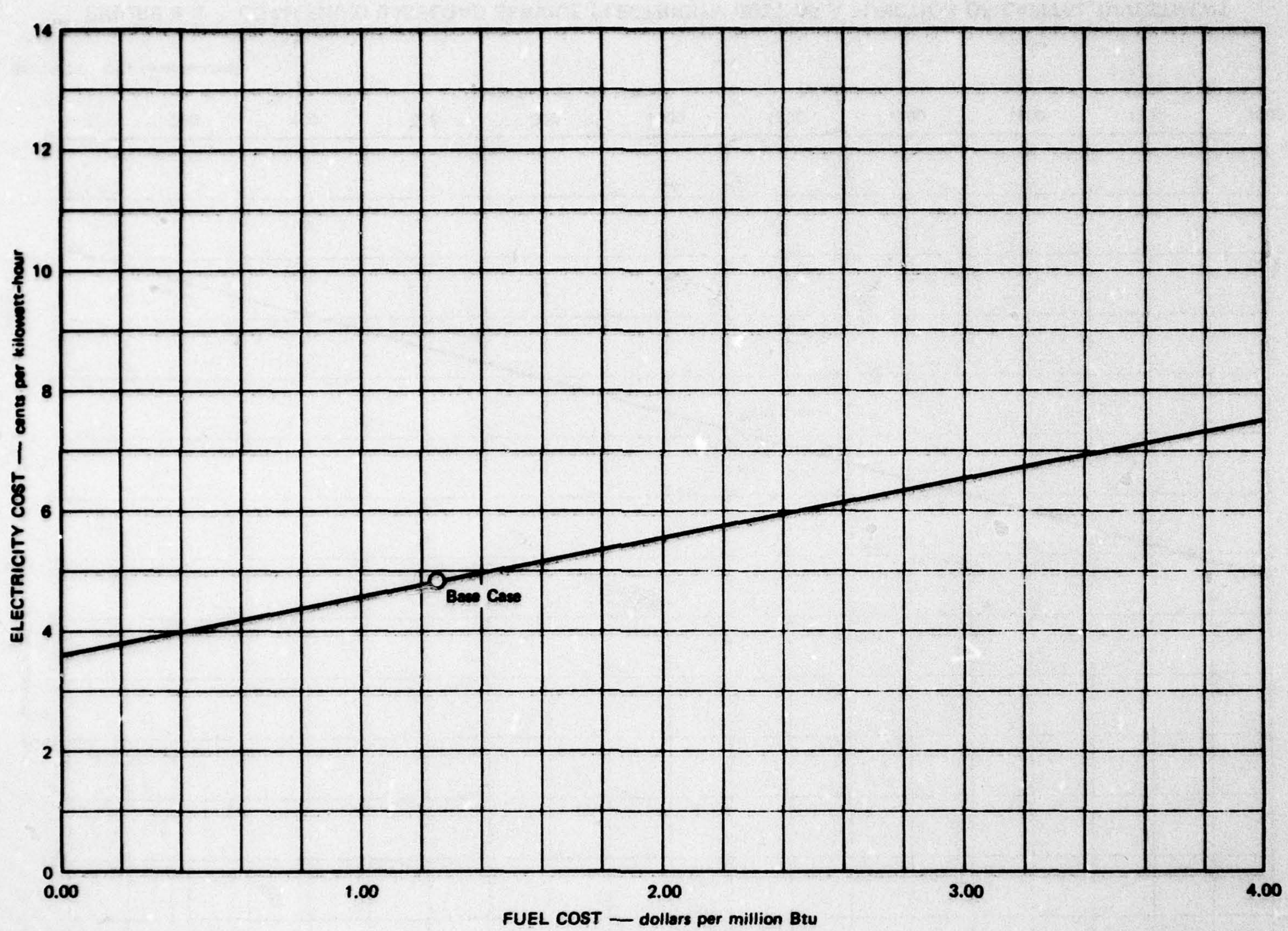
A typical utility has a mix of base-load, intermediate, and peak-load units. If such a utility is taking windpower electricity into its grid to meet some part of the total demand, it will probably accommodate the diurnal variations in the wind by making corresponding adjustments in the output of intermediate units. The appropriate value of the windpower electricity to the utility would logically be only the value of the fuel saved, because the investment in the fossil-fueled intermediate unit would not be affected. As long as utilities are required to maintain or improve their reliability, SRI cannot conceive of a situation in which a utility would be granted a capacity credit for investment in windpower generation facilities.

Figures 3-5 through 3-13 present the costs of electricity from coal-fired steam turbines with flue gas desulfurization (FGD), oil-fired steam



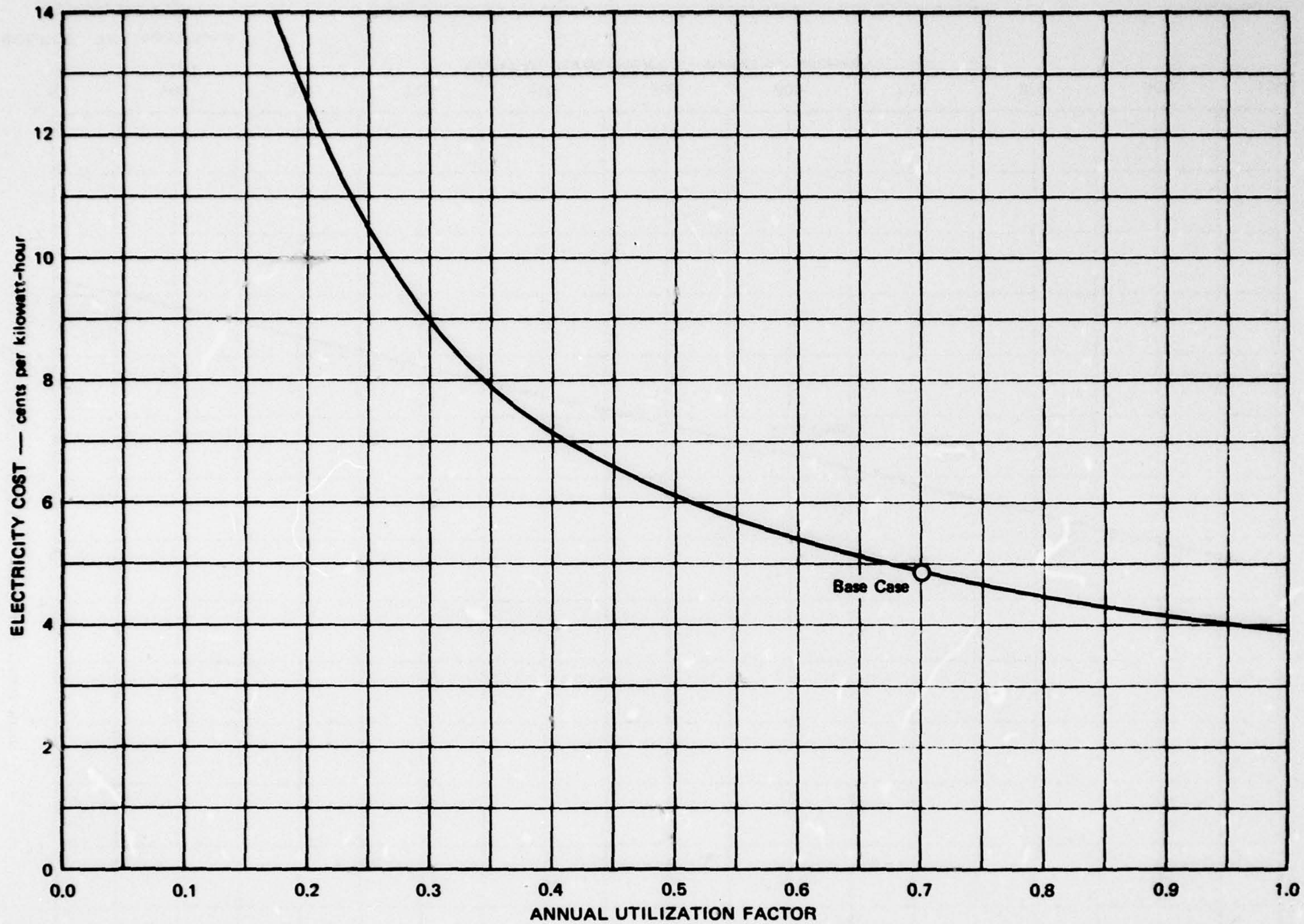
SOURCE: SRI International

FIGURE 3-5 COAL-FIRED BASELOAD SERVICE ELECTRICITY COST AS A FUNCTION OF CAPITAL INVESTMENT



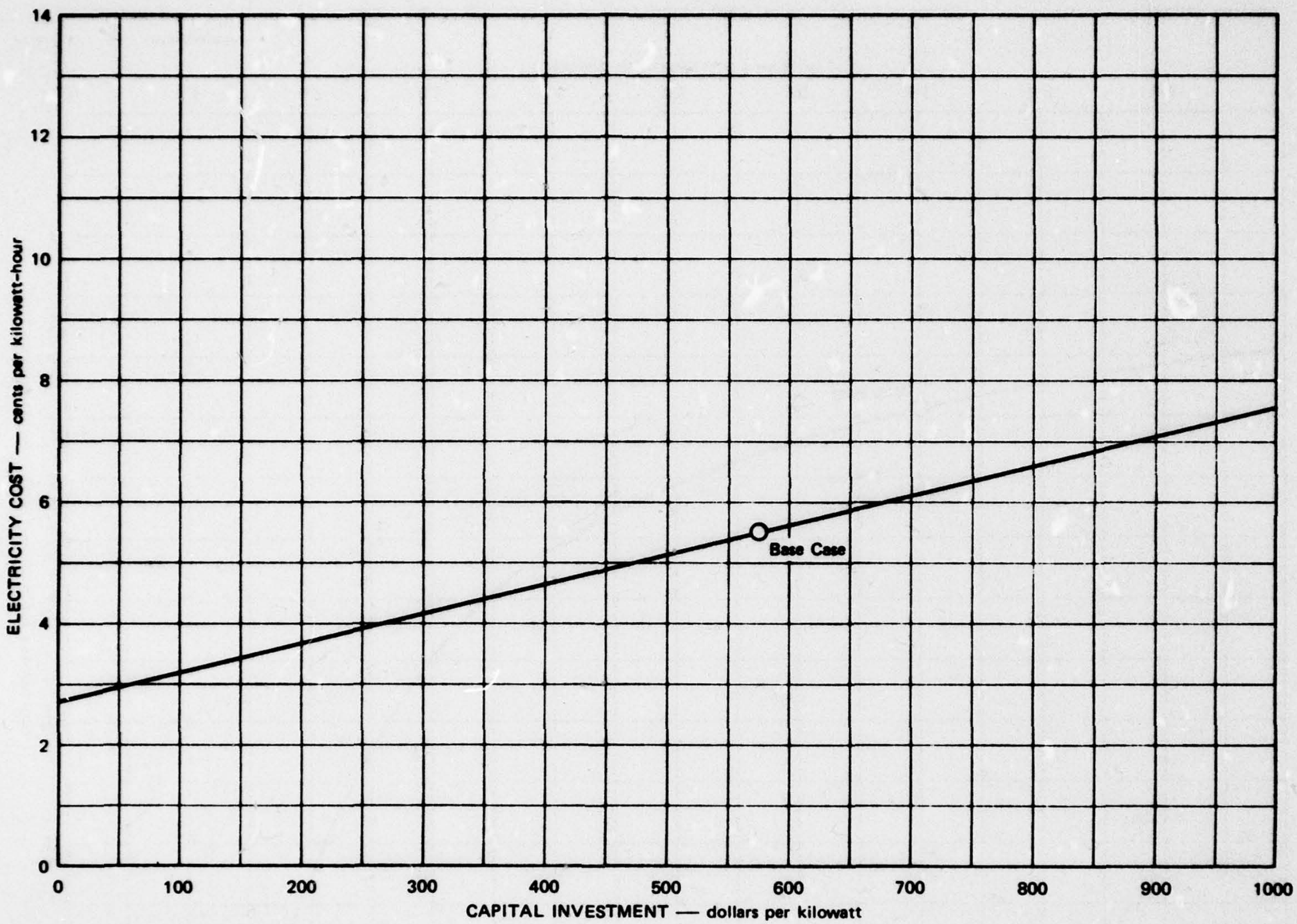
SOURCE: SRI International

FIGURE 3-6 COAL-FIRED BASELOAD SERVICE ELECTRICITY COST AS A FUNCTION OF FUEL COST



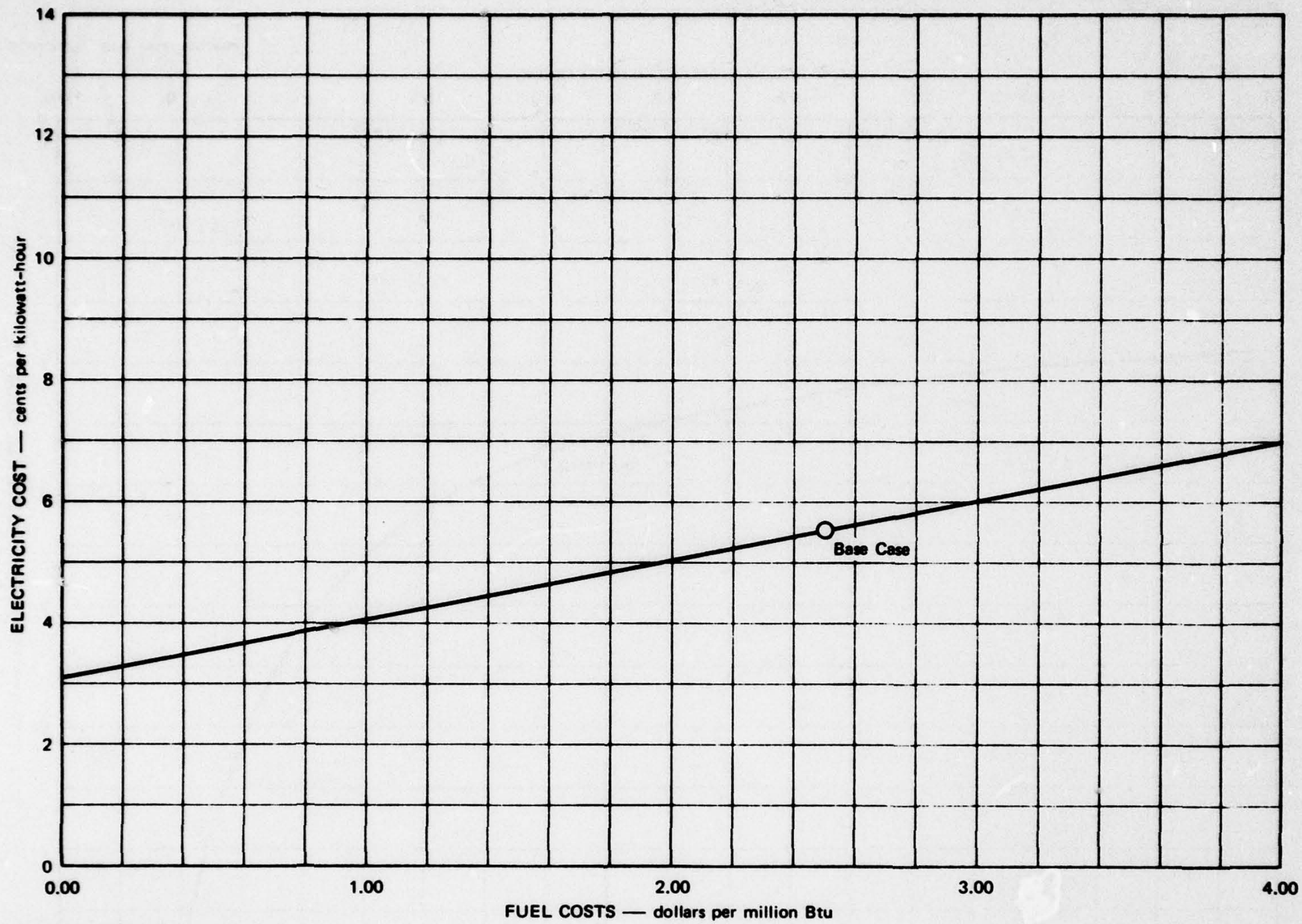
SOURCE: SRI International

FIGURE 3-7 COAL-FIRED BASELOAD SERVICE ELECTRICITY COST AS A FUNCTION OF ANNUAL UTILIZATION FACTOR



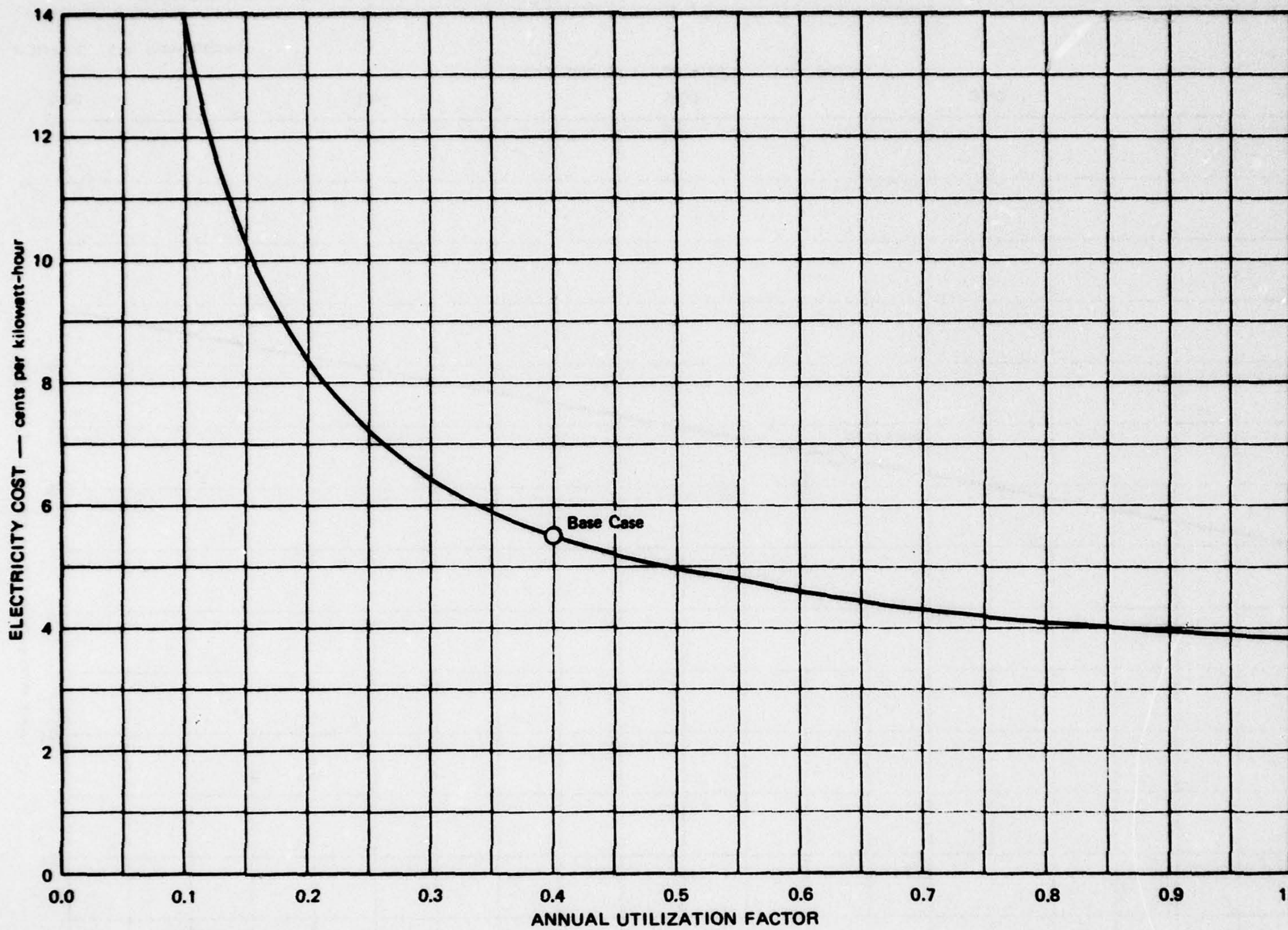
SOURCE: SRI International

FIGURE 3-8 OIL-FIRED INTERMEDIATE SERVICE ELECTRICITY COST AS A FUNCTION OF CAPITAL INVESTMENT



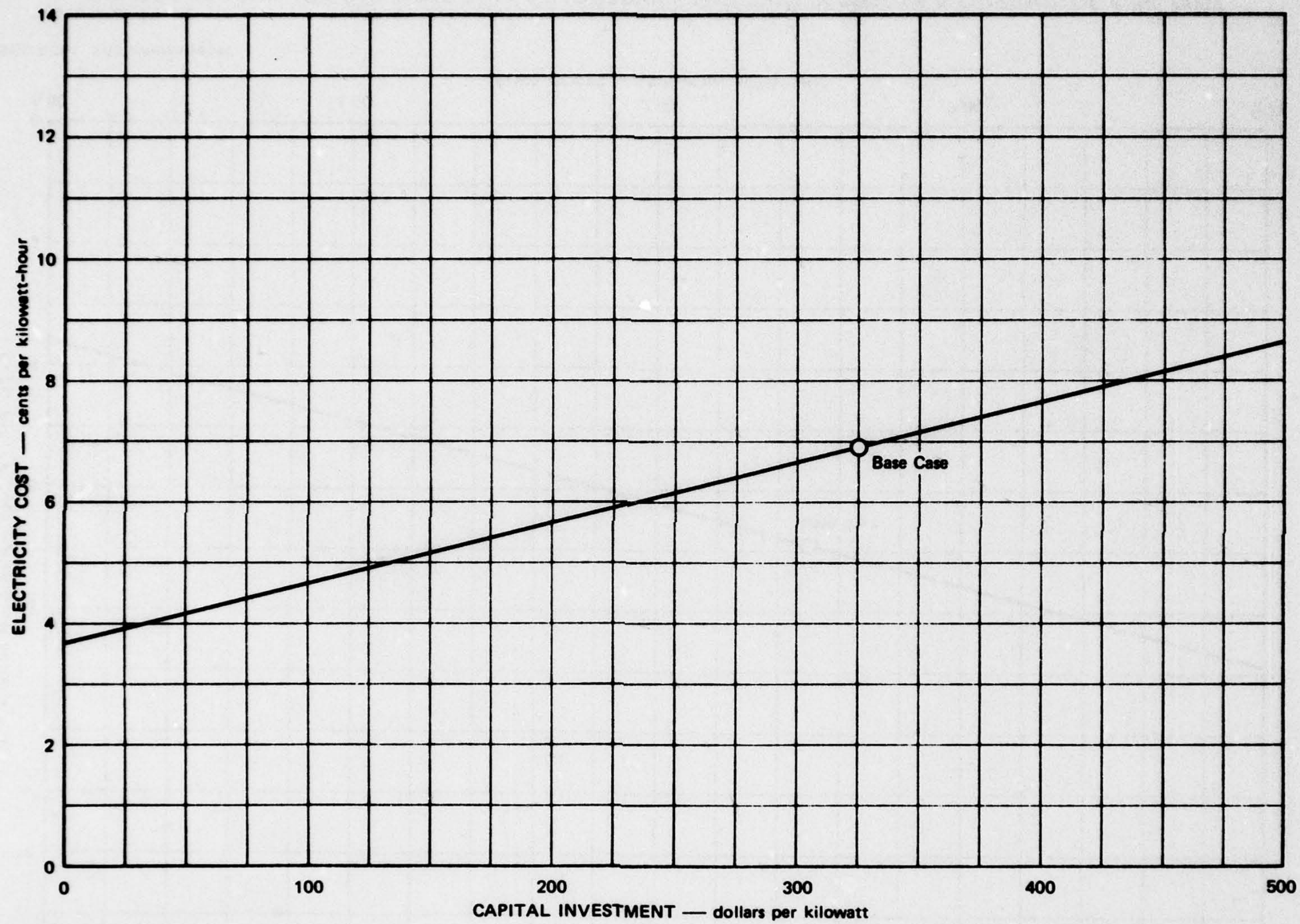
SOURCE: SRI International

FIGURE 3-9 OIL-FIRED INTERMEDIATE SERVICE ELECTRICITY COST AS A FUNCTION OF FUEL COST



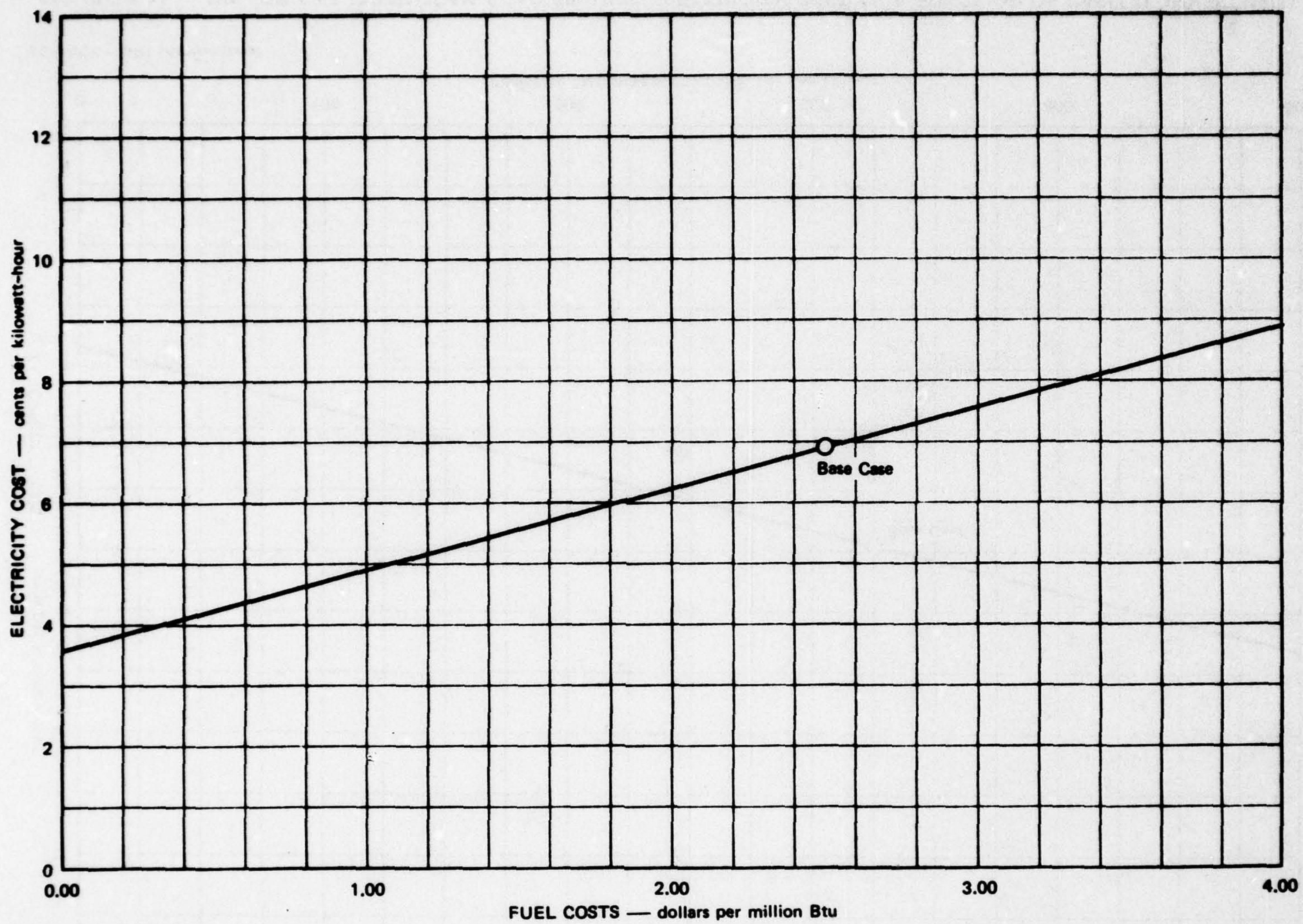
SOURCE: SRI International

FIGURE 3-10 OIL-FIRED INTERMEDIATE SERVICE ELECTRICITY COST AS A FUNCTION OF ANNUAL UTILIZATION FACTOR



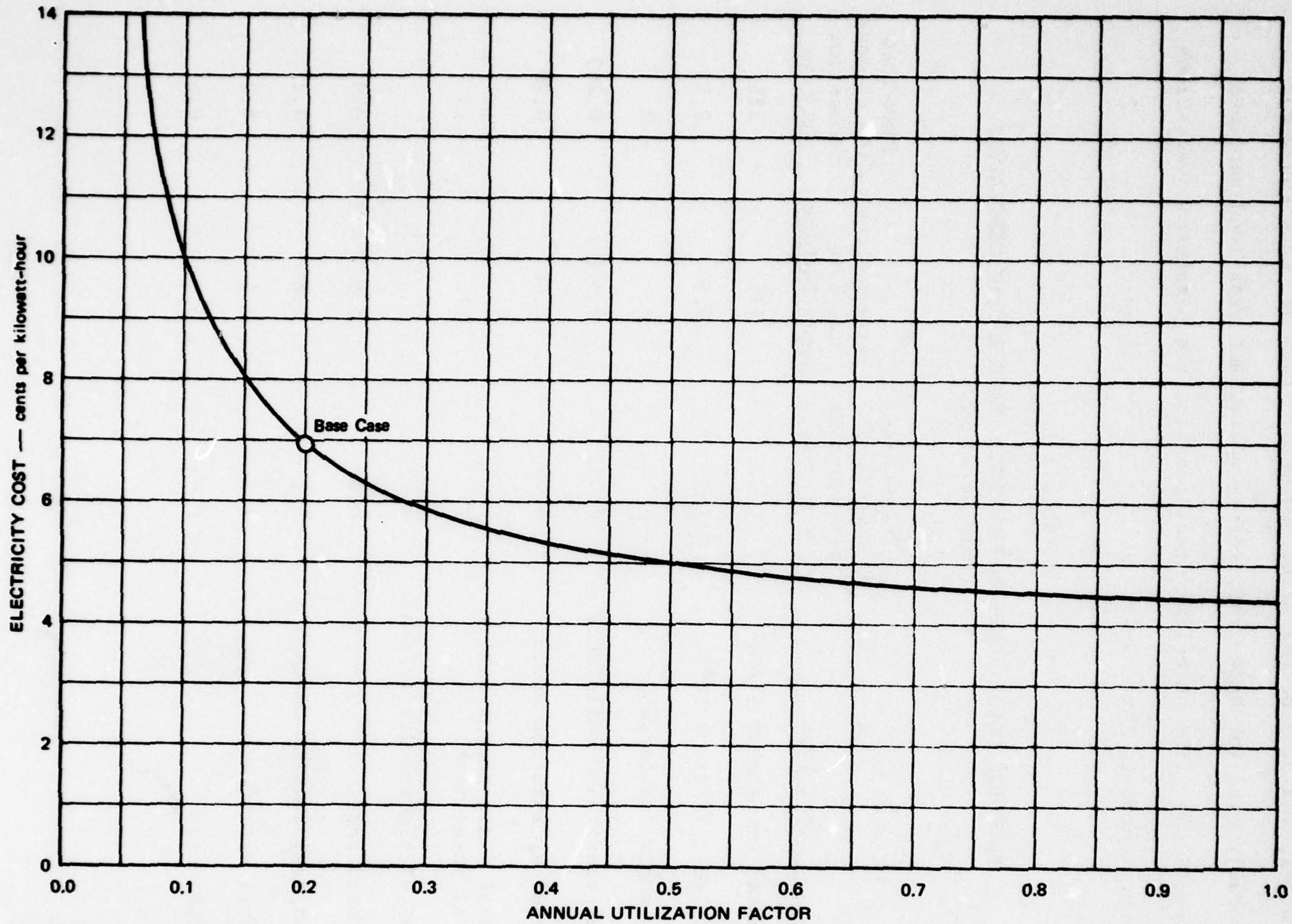
SOURCE: SRI International

FIGURE 3-11 OIL- OR GAS-FIRED PEAK-LOAD SERVICE ELECTRICITY COST AS A FUNCTION OF CAPITAL INVESTMENT



SOURCE: SRI International

FIGURE 3-12 OIL- OR GAS-FIRED PEAK-LOAD SERVICE ELECTRICITY COST AS A FUNCTION OF FUEL COST



SOURCE: SRI International

FIGURE 3-13 OIL- OR GAS-FIRED PEAK-LOAD SERVICE ELECTRICITY COST AS A FUNCTION OF ANNUAL UTILIZATION FACTOP

turbines, and oil- or gas-fired combustion turbines, the equipment generally used for base-load, intermediate, and peak-load services, respectively. The base-line conditions for the parametric variations are presented in Table 3-1.

Table 3-1

BASELINE CONDITIONS--CONVENTIONAL ELECTRICITY GENERATORS
(1979 Dollars)

Unit Type	Base-Load Coal-Fired Steam Turbine with FGD	Intermediate Oil-Fired Steam Turbine	Peak-Load Oil- or Gas-Combustion Turbine
Capital investment ($/kW)	1,100	575	325
Fuel cost ($/Btu × 10^6)	1.25	2.50	2.50
O&M costs (mills/kWh)	6	3	5
Fuel conversion efficiency	0.352	0.352	0.262
Annual utilization factor	0.70	0.40	0.20
Annual fixed charge rate (% of investment)	17	17	17
Cost of electricity (¢/kWh)			
Total cost	4.9	5.5	6.9
Capital-related costs	3.1	2.8	3.2
Fuel costs	1.2	2.4	3.2
O&M costs	0.6	0.3	0.5

When the 2.1¢/kWh base-line cost of windpower electricity is compared with the 2.4¢-3.2¢/kWh fuel cost for intermediate and peak-load service, it can be concluded that the cost of WEGS electricity, under the conditions assumed here, is at practical economic parity with the costs of oil or gas for intermediate and peak-load turbines. Because the windpower is worth the fuel saved, any future fuel cost increases will improve WEGS economic position.

4. INSTITUTIONAL CONSIDERATIONS

Summary and Conclusions

Nonutility ownership and operation of WEGS is being encouraged indirectly and directly by a variety of federal and state actions. The National Energy Act of 1978 consists of five bills, one of which, the Public Utilities Regulatory Policy Act (PURPA), requires that utilities transmit power from small power producers to their customers. Other federal laws, as well as New Hampshire and Maine state laws, that were originally intended to encourage renewal of hydropower generating sites are also conducive to windpower development. Bills now being considered in the House and Senate have sections intended specifically to encourage the wide-scale introduction of wind-generated electricity--up to $1.2 billion in development and construction grants and loan guarantees is being sought. The New Hampshire and Maine Public Utility Commissions are maintaining a current awareness of windpower development and stand ready to ease the products of this technology into the generating mix as they show economic promise or only small economic penalty. Policies that definitely encourage the use of windpower are likely to continue, and may well increase.

Institutional support from utilities is also necessary for windpower development. As a group, the utilities are willing to incorporate WEGS power into their supply, to reduce the use of fossil fuel, provided that the agencies that regulate them will allow recovery of the cost of WEGS

power in the approved rate structure. None of the interviewed utilities considered the reliability of WEGS high because the machines, though they might be mechanically perfect, are subject to vagaries of the wind. Therefore, they are unwilling to revise their plans for building conventional generating units sufficient to meet their total anticipated demand. SRI does not foresee conditions under which utilities will be given transmission or capacity credits for WEGS equipment as long as they are expected to maintain or improve the overall reliability of their supplies.

Public Utility Regulatory Policies Act, 1978

The National Energy Act that was signed into law in 1978 consists of five bills. This subsection will review the provisions of one of those bills, The Public Utility Regulatory Policies Act (PURPA), as it affects power-sharing arrangements such as interconnections, wheeling, or pooling.

Title I of PURPA requires public utility commissions to determine what retail rate structures would result in the most efficient use of the financial and energy resources that are available to utilities. Public utility commissions must hold hearings to consider the appropriateness of time-of-day rates and similar rate standards, and they must then revise their current retail rate structures to conform with the results of these hearings and assessments.

Title II increases the authority of the Federal Energy Regulatory Commission (FERC) as it applies to wholesale power sales. Subjects covered include interconnections, wheeling, and pooling among utilities. The Act provides that cogenerators or small power production facilities may apply to FERC for an order requiring interconnection with the transmission

facilities of any electric utility for the purpose of sale or exchange of electricity at just and reasonable rates. FERC would issue such an order if it determines that this interconnection is in the public interest, or that it would encourage conservation of energy or capital; would lead to optimally efficient use of utilities and resources; or would improve the reliability of the electric utility system. Thus, FERC may require that electric utilities purchase power from a small producer or a cogeneration facility and sell back-up power to those facilities at fair rates.

To qualify as a small power production facility under the terms of the Act, a producer must produce energy solely from a primary energy source (biomass, waste, renewable sources, or any combination thereof); its capacity must not exceed 80 MW; and the generation or sale of electric power must not be the primary business activity of its owner. A "just and reasonable rate" is defined as one that does not "discriminate against" the ultimate consumer, and it may not exceed the incremental cost of the purchasing utility's alternative sources. However, if the small producer is not a regulated utility, it is not guaranteed a fair rate of return, and the rate must include a risk cost. The rules to be promulgated by FERC will exempt qualified cogenerators or small power producers from treatment and regulation as public utilities under state or federal law. A licence will not be required for these facilities as long as they engage only in intrastate power sales and their capacity does not exceed 30 MW.

Power sharing (pooling) arrangements may also be ordered by FERC if the arrangement conserves energy, furthers efficiency, and improves reliability. PURPA has special provisions to cover wheeling. A purchasing

utility may apply to FERC for an order requiring any other electric utility to provide transmission services from the small power producer to the applicant utility, even if such services require enlargement of transmission capacity. However, no order may be issued if that order results in uncompensated financial loss, places an undue burden on an electric utility, or impairs reliability. The applicant must reimburse the utility for its costs. These provisions enable the small power developer to negotiate for the sale of power outside the utility franchise area in which his plant is located.

Public Utilities Commission of New Hampshire

Before PURPA was passed, the Public Utilities Commission of New Hampshire held hearings on rates for small power producers. In April 1979, the Commission ordered that utilities that purchase electricity from small power producers in a utility's franchise area must purchase the entire output offered for sale from all such small plants that do not use nuclear or fossil fuels and whose capacities do not exceed 5 MW. New Hampshire exempts power facilities of less than 5 MW from all rules, regulations, and statutes applying to public utilities, in an effort to increase the use of small dams. The Commission has determined that encouragement of small production facilities is in the public interest because it may lessen the state's reliance on other sources of energy that may become uncertain. As a result of these decisions, small windmills and solar energy devices in New Hampshire may be subject only to municipal zoning or building code regulations.

During the hearings, the Commission heard testimony from a large number of witnesses, and considerable controversy arose over the definition of the "incremental cost" of the purchasing utility's alternative sources that appears in PURPA. PURPA describes "incremental cost" as the cost of power from other sources that are supplanted by the use of power from the small power producer. The Commission decided not to limit the scope of the hearing to "incremental cost" and requested that all elements of cost be submitted for consideration. Much of the cost information that was presented as evidence was published in a 1977 report by the New Hampshire Governor's Commission on Hydro-Electric Energy (NHGC, 1977). Information from this report and other information submitted at the hearings is summarized below.

- "Incremental cost" in 1978 dollars estimated by Public Service Company of New Hampshire (PSNH)--2.2¢/kWh
- Interim rate currently paid to Goodrich Falls and other small hydro producers by PSNH and the New Hampshire Electric Cooperative (NHEC)--2.0¢/kWh*
- Estimated cost in 1980 dollars of generation from restoration of five hydroelectric plants with less than 1 MW of capacity each--5.8¢-7.89¢/kWh (NHGC, 1977)
- Estimated cost in 1980 dollars of restoration of six hydroelectric plants averaging 35 MW of capacity each--11.9¢-15.1¢/kWh (NHGC, 1977)
- Projected average cost from 1983 to 1993 of power from the Seabrook nuclear unit (currently under construction)--4.5¢-5.0¢/kWh
- Actual cost of power from initial operation of Wyman #4, an oil-fired plant in the system of Central Maine Power Company (CMPC)--7.74¢/kWh
- Estimated cost of power from Wyman #4 operating at increased capacity factor--4.5¢-5.0¢/kWh

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*Goodrich Falls later testified that this price resulted in a loss.

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A FEASIBILITY STUDY OF WINDPOWER FOR THE NEW ENGLAND AREA.(U)

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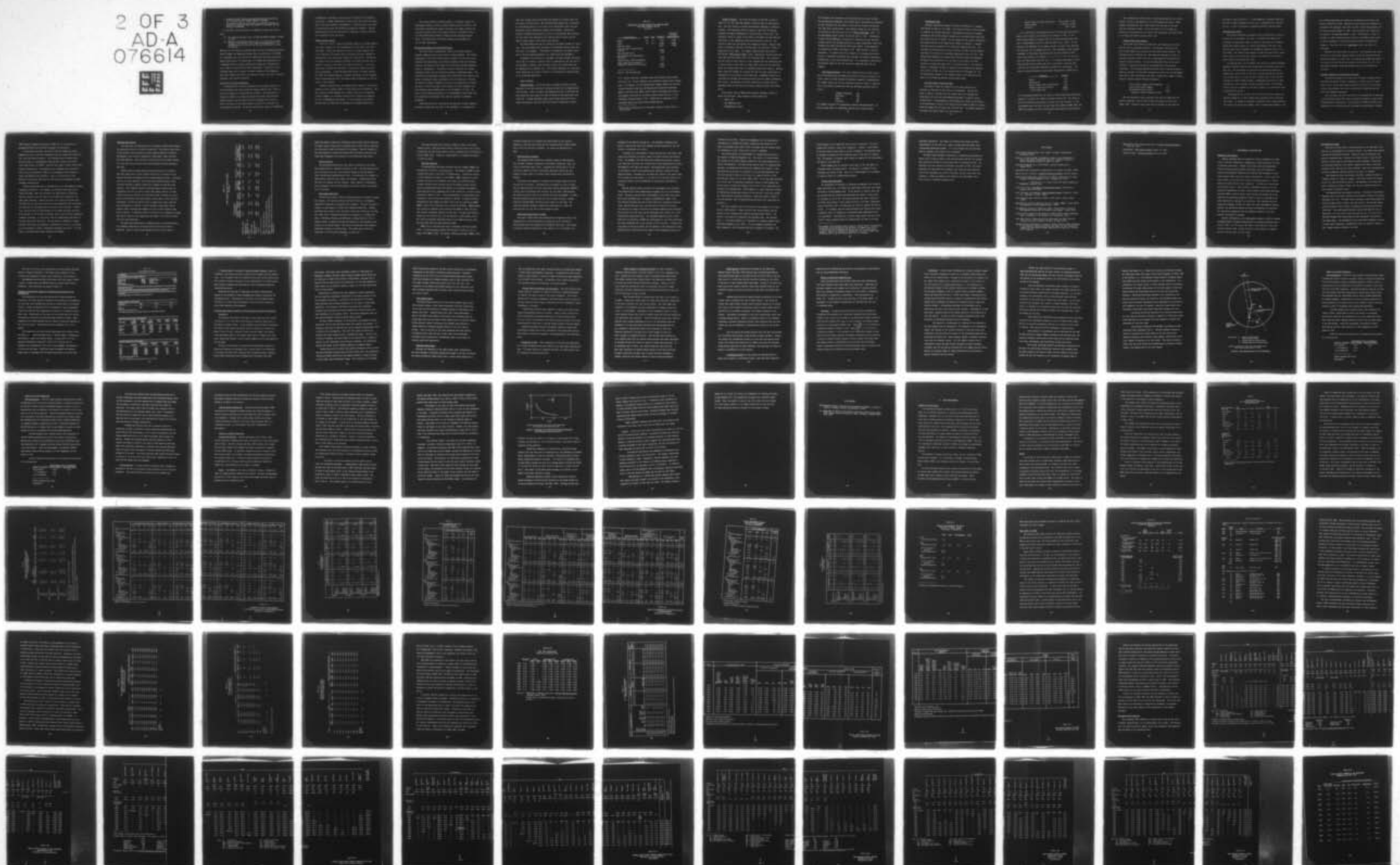

- Proposed contract between Lawrence Hydroelectric Associates and New England Power Company (NEPCO)--4.28¢/kWh
- Price paid by PSNH for entitlement in combustion turbines to Connecticut Light and Power--42.53¢/kWh; to Fitchburg Gas and Electric--12.09¢/kWh.

On the basis of this evidence, the Commission reached two conclusions.

(1) The combined wholesale rates of PSNH and NEPCO averaged 3.2¢/kWh in 1978.

(2) Favorable consideration must be given to reliability and cost savings to the utility at the time it purchases power. The probability that a unit will be on-line will affect its value as capacity.

Therefore, in the absence of specific FERC rules and rule-making procedures based on PURPA, the Commission decided that an interim rate of 4.5¢/kWh is a reasonable price for electricity from plants that will provide both capacity and energy. An interim rate of 4.0¢/kWh was determined to be a reasonable price for plants that provide energy only intermittently (e.g., WEGS or run-of-the-river hydro facilities). The prices set for purchased power will be subject to annual revision by the Commission, which will examine such factors as capacity, energy, size, price, existing equipment, and financial stability.

Maine Public Utilities Commission

The Maine Public Utilities Commission is now legally permitted to accept windpower and other alternative energy production as a result of the recent passage of a supporting law in Maine. The legislation is modeled on PURPA in its important aspects and allows the alternative energy producers and utilities free rein in making their contracts. Only if one party or the other refuses to enter into a contract will the Commission intercede. If the two groups cannot agree, the Commission

is empowered to determine a fair price for the energy to be bought by the utility. Present indications are that a fair price would be equivalent to the fuel savings of intermediate- or peak-load units that would be throttled back when the alternative energy was available. Serious consideration is not now being given to including a capacity credit in the calculation of the fair price.

Pending Federal Support

Title X of the U.S. Senate 1979 Energy Supply Act (S.1308) mandates the study, construction, and implementation of both small- and large-scale WEGS. During the hearings on Title X, it became apparent that a real difference of opinion exists on whether sufficient emphasis is being placed on the small-scale (100 kW to 1 MW) systems. Differences of opinion were also expressed on whether a discussed national goal of 500 MW of installed wind capacity by 1986 was realistic. It was contended that 1,000 MW was reasonable if small-scale systems were given more encouragement. S.1308 now seeks $200 million of federal funding (in 1980) for windpower applied to federal buildings, and the companion House of Representatives bill (H.R.3558) seeks an additional $1 billion (over a 7-year period).

Industry representatives are seeking greater support of small-scale systems so that a greater number of likely sites can be considered. The wind resources of New England do not require this sort of compromise, in SRI's judgment, so economies of scale can be realized by planning for the 2.5 MW WEGS in this region. In fact, 400 MW of the 500 MW national goal for 1986 could be absorbed by the NEPOOL system alone.

The proposed federal financial support of windpower ranges from development funding to direct purchase subsidies and tax credits. The wind machine manufacturers support funding at all stages, whereas the utilities express concern that federal financial involvement carries the usual bureaucratic burden of regulation and reporting requirements. The final extent of federal funding and involvement has not yet been established.

Revenue Requirements and Fixed Charge Rates

The term "revenue requirements" refers to the basic method of economic comparison used by the electric utility industry. The revenue requirement is the total revenue that is required to cover fuel costs, operations and maintenance, depreciation, property taxes and insurance, interest, and federal income taxes, and to provide a minimum acceptable return to stockholders. The method is used to calculate the minimum acceptable revenue for each alternative method of generating power. The selection of new generation equipment has traditionally been based on the desire to minimize revenue requirements over the long term. Recently, in reaction to radical changes in the price and availability of capital and fuel, utilities have been under pressure to select equipment that will minimize capital expenditures or oil consumption, or both. The focus of the following discussion is on determining a fixed charge rate for evaluating the investment that would be required in windpower generation.

First-year costs for a facility do not take into account changes in the value of money over the life of the investment. To recognize the

time cost, present worth calculations are applied to levelize costs over the period of construction. The levelized fixed charge rate is expressed as a percentage applied to the value of the installation that will give the annual revenue required to support the investment. Because the facility is depreciated annually, the net or "unrecovered" value declines over the years, and consequently the required rate of return (and the federal income taxes on that return) also decline.

The fixed charge rate may be converted to an annual uniform or "level" rate. The fixed charge rate expressed as a percentage reflects more than the return on investment. ("Investment" is defined as the present worth cost of the anticipated expenditure on construction and equipment.)

In addition to the return on investment, one must consider the direct costs that are related to capital (that is, depreciation over the life of the equipment, insurance, and ad valorem taxes); and income taxes must be considered as an indirect cost. The various components of a levelized fixed charge rate are listed in Table 4-1 and discussed in greater detail in the following subsections.

Rates of Return

Return on Bonds. The 9% rate that is allowed for bonds is representative of the rate that would currently be paid for the highest-grade utility bonds. Sales of bonds by New England utilities in 1979 have not been traced for this study, but rates for bonds in this group must be at least 10%. Through tax-exempt bonds, public power groups are able to obtain financing at rates far below the 9% that is mentioned in Table

Table 4-1

COMPOSITION OF FIXED CHARGES FOR INVESTOR-OWNED UTILITIES--TYPICAL VALUES
(Percent)

Capitalization	Ratio	Rate	Weighted	Proportion of Total Capitalization
Bonds	50	9	4.50	0.439
Stock	50	11.5	5.75	0.561
Required return			10.25	1.000
Less earnings on depreciation reserve			2.75	
Net required return			7.50	
Add straight line depreciation writeoff			3.33	
Income taxes at 48% (normalized)			3.88	
Local taxes (ad valorem) and insurance (based on initial cost)			2.50	
			17.21	

Source: SRI International

4-1.* Recent long-term, tax-exempt bonds have offered yields between 6.54% and 7.5%. Private companies can occasionally make similar arrangements. For example, the New England Power Company (NEPCO) has recently received financial help from the Massachusetts Industrial Financing Agency, which will give NEPCO a $96.5 million tax-exempt bond issue to help finance conversion of the Brayton Point station from oil to coal (Air/Water Pollution Report, 1979). NEPCO will be competing in the tax-exempt market with public and municipal groups.

*Public power financing will be discussed in greater detail later in this section.

Return on Equity. The return on equity (11.5%) that is used in Table 4-1 is a rate that New England's utilities would be gratified to earn. The term "return on equity" has different meanings in different contexts. The accounting return on equity is the ratio of earnings available to common stockholders to the book value of the stock. The investors' return on equity is the ratio of dividends plus the year-end stock price to the beginning of the year stock price less one. The results of these two calculations are frequently similar. However, when stock is selling at less than its book value, the investors' return on equity will be far lower. For example, PSNH recently sold stock at \$19.50/share (Wall Street Journal, 1979), although the 1978 year-end book value was \$23.32 per share (thus, the ratio was 0.84). The investors' rate of return on this utility is 3.2%, compared with the accounting rate of return, which is more than 7%. When stock is sold at less than book value, the average book value of outstanding shares will decline. Furthermore, unless the company can increase the rate of return sufficiently to compensate for the decrease in the book value, a permanent reduction in the growth of earnings and dividend potential for all common stockholders will result. The majority of utility stocks have recovered from the depressed levels of 1974 and are currently selling at about 97% of book value.

State public utility commissions determine allowable returns on equity for utilities. Rates allowed in three states are:

- Maine--12%
- New Hampshire--14%
- Massachusetts--13.5%.

The "allowed" rates establish the accounting rate of return, but they are nevertheless misleading. The allowed rates listed would be attractive to some investors, but the nation's utilities are actually earning far less than their allowed rates. The national average for all utilities is currently at the 1974 level of 11.7% (Utility Spotlight, 1979). In the New England states listed, the current rate is 7-8%. Furthermore, in Maine and New Hampshire, the quality of earnings has also declined. In Maine, 48% of the earnings available to common stockholders comes from Allowance for Funds Used During Construction (AFDC); in New Hampshire, the proportion of AFDC in earnings is 52%. AFDC provides no cash for operations. It reflects the cost of capital for on-going construction projects. When AFDC is deducted from earnings, the balance remaining is insufficient to cover the dividends paid. As a consequence, depreciation and deferred taxes are the only sources of operating funds for the company.

Total Required Return. The total required return (10.25%) used in SRI's calculations may be compared with rates of returns, presented in a recent report by Thermo Electron Corporation (undated) of Massachusetts. The company stated that certain industries would not invest in cogeneration if the project yielded less than the following required rates of return:

Chemical industries	15%
Petroleum	16%
Paper	15%
Utilities	13%

The primary criterion is an acceptable interest coverage multiple, 3.0 before income taxes, or comfortably greater than 2.0 after taxes.

Depreciation Rate

Economic evaluations frequently include an addition for a sinking fund (which in Table 4-1 is 0.58%). The format of Table 4-1 was developed to simplify the current discussion. Depreciation reserves are normally reinvested, and the SRI analysis assumes that reinvested funds would earn the required return of 10.25%. For the purpose of the current evaluations, the annuity portion of the depreciation charge is required. A sinking fund factor must be applied to the first-year depreciation rate. The straight-line depreciation rate over 30 years is 3.33%, less the sinking fund factor of 0.58%, for a reinvested depreciation rate of 2.75%. (The sinking fund deduction was obtained from interest tables and represents the amount that would have to be set aside in an account at 10.25% interest to recover the first cost in the same 30 years.) The required return on investment (10.25%) is reduced by the earnings on the depreciation reserve (2.75%), for a net required return on investment of 7.5%. The depreciation charged on the company's books is not affected by the amount of the financing obtained from borrowed funds.

Levelized Federal Income Tax Rate

The federal income tax component of the fixed charge rate is developed on the basis of the return to stockholders. The tax rate shown in Table 4-1 assumes that the company would use straight-line depreciation for both tax and bookkeeping purposes, a practice called "normalizing." In developing the fixed charge rate, taxes are calculated on the proportion of stock in the required return shown in Table 4-1 (0.561), using the charge for net return and a 48% tax rate. To simplify equations (see Grant and Ireson, 1964), the calculation is:

Return earned on equity proportion:	7.5% x 0.561 = 4.21%
Pretax income:	4.21/0.52 = 8.10%
Tax rate:	48% = 3.88%.

If a liberalized tax depreciation method is used (sum-of-the-years'-digits over 30 years), the income tax is reduced to 2.87%. In the years'-digits method, the amount that can be taken as depreciation each year is established by use of a fraction (Hunt et al., 1961). In this fraction, the numerator is the number of years of useful life remaining for the plant, and it changes each year. The denominator, which remains unchanged, is the number representing the sum of the digits of full life of the property; for example 1 + 2 + 3 + 4 + 5 = 15. In the first year, the depreciation would be 5/15. It is always advantageous to have funds available early rather than late in the plant's life, and many utilities use accelerated depreciation methods for tax purposes. The effect of using liberalized (accelerated) depreciation is shown below:

Component	Percent
Return	7.50
Depreciation	3.33
Federal income taxes (liberalized)	2.87
Property taxes and insurance	2.50
Fixed charge rate	16.20

In the *foregoing tabulation*, the effect of using liberalized depreciation methods is to reduce the income tax burden by about 25%. The saving is held in the deferred tax reserve or passed on to the consumer. In the New England area, the three utilities that were examined (PSNH, CMPC, and NEES) all reported the use of accelerated depreciation for tax purposes.

The investment tax credit, which is discussed extensively in a later section, is also a consideration in the fixed charge rate study. Under ordinary circumstances, this credit reduces the tax paid in the year that the investment is made. If the tax credit of 5.7% (common for utilities) is amortized over the life of the investment, the effect would be to reduce the 48% tax rate by about 1.2%.

Property Taxes and Insurance

Local taxes vary widely by jurisdiction, and insurance costs vary with the type of equipment installed. For instance, insurance rates will be much higher for utilities with installed nuclear capacity. The levelized rate of 2.50% used for local taxes and insurance in Table 4-1 is based on initial (first) cost and is representative of rates for the electric utility industry. If only the depreciated value of the plant is taxed, a levelized value must be determined with a year-by-year calculation. The following tabulation presents the ad valorem (property) taxes as a percent of total plant investment at first cost for New England utilities in 1978 (calculated on the basis of data from a number of Edison Electric Institute Uniform Statistical Reports):

Public Service Company of New Hampshire	1.5
Central Maine Power Company	1.4
New England Electric System	2.9
Average ad valorem (property) taxes	1.9

SRI has obtained an actual insurance rate only for PSNH, which reported an insurance rate of 0.07% of plant investment at first cost (PSNH, 1978). Franchise taxes would also be included in the local tax

rate that is used in Table 4-1. In New Hampshire, franchise taxes will be 0.25% of plant investment at first cost; in Massachusetts, they will be 0.4%. It was not possible to determine franchise taxes for Maine.

Investment Tax Credits

The federal government encourages capital expenditures by industry by means of the investment tax credit. A business that makes a new investment in depreciable assets is granted a reduction in its federal income tax liability equal to a certain percentage of the asset cost. The tax credit can be obtained only through tax reduction and not by a tax refund. Tax credits can be applied to past and future years' income taxes (3 years in the past and 5 years in the future) if the current year's taxes do not offset the credit.

By reducing taxes, the investment tax credit also reduces operating expenses, required revenues, and average costs of electricity per kilowatt hour. The investment tax credit may be deferred and amortized (normalized) over the life of the asset, thereby reducing the purchase cost of that asset, or it may be used to reduce taxes in the year the investment is made (flowed through). Normalization results in a long-term benefit to the customer and does not affect rates. Flow through reduces rates for customers in the year in which it is received but does not benefit the utility.

The Energy Tax Act of 1978, one of the five acts that comprise the National Energy Act of 1978, changed some provisions of the investment tax credit. To stimulate investment in property used to supply alternative sources of energy (for example, solar or wind energy property), the

Act provided additional tax credits for investment by both public and private (nonutility) firms. Nonutilities will receive the regular, nonrefundable 10% investment tax credit on solar or wind energy property for the period ending December 31, 1980. This 10% regular tax credit will be reduced to 7% beginning January 1, 1981. From October 1, 1978, to December 31, 1982, nonutilities will receive a refundable energy credit of 10% of investment in alternative energy property (including wind property). Note that this is an <u>additional</u> credit, and that it is refundable.

Different provisions apply to utilities. The investment tax credit for solar or wind energy property owned by utilities includes only the regular percentage at a lower rate. The regular percentage that applies to utilities will be 10% on four-sevenths of the value, or 5.7%. The additional refundable energy percentage credit is not available to utilities.

<u>Potential Regulatory Influences on Wind Power</u>

The National Energy Act of 1978, which includes the Energy Tax Act and PURPA, has denied utilities a monopoly on certain sources of power. These sources include small power production facilities, such as hydroelectric installations that can be reactivated or rehabilitated, and solar and windpower generators.

The investment tax credit provisions of the Energy Tax Act described in the preceding subsection clearly encourage development of small power installations by nonutilities. The provision of PURPA described at the beginning of this section may also encourage such development, although

PURPA requires judgmental decisions by FERC, and it is too early to determine how FERC will interpret and apply its provisions.

As discussed previously, the Public Utilities Commission of New Hampshire has set a "just and reasonable rate" for energy from facilities with less than 5 MW of capacity. The allowable rate for plants that produce energy on a nondependable capacity basis (such as run-of-the river hydro plants) is 4¢/kWh. This rate will apply to power from a small windmill installation. The Commission will reexamine this issue when final rules are published by FERC, and the Commission also intends to adjust the approved rates annually. Thus, it is too early to tell whether the rates that have been set will favor the development of small windpower installations.

Existing regulations may be disincentives to the development of small, independent operations. For example, the Franklin Pierce Law Center (Brown and Ringo, 1979) has considered the implications of requiring that the utility be the sole buyer of the electricity produced by the small power developer. Because the price to be paid to the small power developer must be lower than the price of the generation that is replaced, the incentive for developing small facilities will be minimal. Furthermore, the sites that are unprofitable for the small developer may still be profitable for the utility to develop; thus, as the utility's marketing dominance increases, it could come to own an increasingly large share of the small generation facilities. The Law Center's preliminary analysis indicates that legal and regulatory constraints may be the major obstacle to the development of small, independent hydropower facilities. The same kinds of constraints may affect windpower development.

Ownership Alternatives

The lower rate of financing that is available to public power groups was mentioned briefly in an earlier subsection. The publicly owned sector of the electric utility industry includes federal agencies, municipal governments, rural electric cooperatives (REA Coops), power districts, and state agencies. These electric utilities are able to obtain capital at a cost lower than the price that investor-owned utilities generally must pay.

Federal projects obtain capital directly from the U.S. Treasury. REA coops obtain part of their capital from the U.S. Treasury and the balance from their own banks and other nongovernmental sources. Municipals are able to raise capital at rates below those prevailing for private utilities because no federal income tax is imposed on municipal bond interest. This exemption permits a municipal power system to pay its bondholders only the net rate of return they demand, whereas a private utility must pay an interest rate that would yield a similar net return after the bondholders have paid personal income taxes on their interest. Furthermore, the publicly owned sector is exempt from direct taxation. These systems pay no federal or state corporate income taxes, and no property taxes, although some payments in lieu of local property taxes may be required. In addition, public utilities are not regulated, although they may be subject to the regulations that apply to the units in which they have joint ownership.

The Small-Scale Hydroelectric Program provides an interesting basis for comparing financing for privately owned facilities with public financing. Table 4-2 shows fixed charge rates for various types of

Table 4-2

FIXED CHARGE RATE FOR VARIOUS OWNERS
(Percent)

	Investor-Owned Utilities			State-Owned Projects		Municipally Owned Projects		Small Hydroelectric Development	
	Normal Financing	Tax-Free Bonds	Federal Projects	SRP*	LCRA†		REA‡ Coops	Industrial	Private
Required return	10.25	9.50	3.00	6.80	7.50	6.80	4.4[1]	15.00	13.00
Depreciation (sinking fund, 30 years)	0.58	0.58	0.58§	0.58	0.58	0.58	0.58	0.58	0.58
Income taxes	3.88	3.49	--	--	--	--	--	0.46	0.45
Local taxes and insurance	2.50	2.50	--	3.60	--	0.10	1.30	2.50	2.50
Total	17.21	16.07	3.58	10.98	8.08	7.48	6.28	18.54	16.53

*SRP = Salt River Project.

†LCRA = Lower Colorado River Authority.

‡REA = Rural Electrification Administration.

§Depreciation is variable and would be charged at the cost of major repairs in the year of expenditure.

owners and kinds of financing, including investor-owned utility financing by normal capital sources and by tax-free bonds; public utility financing; and financing for small hydroelectric development. Specific examples of the rates applied to various facilities under alternative ownership and financing arrangements are presented in the subsections that follow.

Federal Agencies

The Snettisham Hydroelectric dam, which is operated by the Alaska Power Administration, commenced operation in 1976. The Snettisham project pays 3% interest, the full rate currently charged on federal developments (Alaska Power Administration, 1979). No deductions are allowed for depreciation, income or local taxes, or insurance. Administrative and O&M costs are charged into the accounts. Major repairs or replacements will be charged in lieu of depreciation in the year in which the expenditure is incurred.

State-Owned Facilities

The Salt River Project (SRP) of Arizona operates as a federal reclamation project. The project provides electrical service to residential, commercial, industrial, and agricultural customers. SRP uses electricity revenues to help support its water and irrigation operations. Sinking fund bonds were issued in July 1978 that yield 6.8% if held over the long term (SRP, 1978). Depreciation expense is computed on a straight-line basis. SRP makes voluntary contributions to taxing bodies in lieu of property taxes, in amounts that must be approved by the Secretary of the Interior of the United States. The State of Arizona has filed lawsuits requesting increases in certain years. The amount paid in 1977 was equivalent to 3.6% of plant investment at first cost.

The Lower Colorado River Authority (LCRA) in Texas is an entity similar to SRP. Long-term bonds issued in 1978 will yield 7.5% if held to maturity, but may become subject to early redemption at the Authority's option (LCRA, 1978). Property is depreciated on a straight-line basis; no taxes are paid.

Municipal Agencies

The Massachusetts Municipal Wholesale Electric Company (MMWEC) was incorporated in 1969 as a planning agency. The members of MMWEC include 28 towns and cities in the state of Massachusetts. Legislation enacted in 1973 permitted the group to join NEPOOL. MMWEC organizes the power purchase contracts of its members, has entered into wholesale power purchase contracts with existing nuclear and pumped storage projects, and has purchased ownership participation in all planned New England generating facilities, beginning with 22 MW in Wyman No. 4, which started operating in Maine in 1978. Total participation in investor-owned units installed or under construction amounts to 928 MW. A further 473 MW in combined-cycle and combustion-turbine units will be installed by MMWEC. MMWEC's share of the Seabrook units is now 19.5% (448 MW). MMWEC members have elected to terminate their contract with NEPCO in 1981, and they must provide replacement capacity by that time. The group was denied a permit for an oil-fired unit, but the decision is under appeal, and it has recently purchased additional shares of the Seabrook nuclear units from the block that was being offered by PSNH.

MMWEC sold a long-term bond issue in September 1978 that yielded 6.80%. A recent prospectus offers $150 million in bonds for sale in August 1979 (MMWEC, 1978). The group's operating statement (MMWEC, 1978)

includes a deduction for straight-line depreciation at 3%, interest expense at 2.8%, and local taxes paid on the Wyman plant in Maine amounting to 0.1% of first-cost investment. No income tax deductions are made.

Rural Electric Borrowers

The Dairyland Power Cooperative combines a group of REA borrowers that includes 29 member cooperatives in Wisconsin, Minnesota, Iowa, and Illinois (Dairyland Power, 1978). Dairyland has constructed or is constructing a number of jointly owned power generation facilities; the largest of these, which is currently under construction, has 350 MW of capacity.

The current rate charged to borrowers by the federal REA is 5% (the rate was 2% in the past). Dairyland will be drawing on a line of credit with the National Rural Utilities Cooperative Finance Corporation (NRUCFC), at 3%/y, with certificates maturing after the year 2020. REA borrowers may obtain from 10% to 30% of the capital they need from NRUCFC. In 1978, Dairyland obtained financing from the City of Alma, Wisconsin, through long-term (through 2008) pollution-control bonds at 6 and 1/8%. The operating statement charges straight-line depreciation at 3.33%; the local tax rate is 1.3%, and no income taxes are paid.

Small-Scale Hydroelectric Program

The focus of DOE's Small-Scale Hydroelectric Program has been on the rehabilitation of retired hydroelectric dams and on the retrofit of existing dams that were equipped with hydropower facilities. The program is directed toward installations in the range of 0.5 to 15 MW and is an

outgrowth of the National Energy Act. The favorable treatment being given to nonutilities under this program has been discussed in the subsection on investment tax credits.

To promote the redevelopment of small hydroelectric facilities, some states are providing no-interest loans, and others provide low-interest loans. For example, New York State will provide zero-interest construction loans for nine sites (all of which are retired hydroelectric plants). New Hampshire will make low-interest, state-guaranteed loans available to developers of small-scale hydroelectric projects, through the Water Resources Board. Alternatively, the Board may construct and operate dams for the public use and benefit, or it may do so for private benefit on a contractual basis, with the permission of the Governor and Executive Council.

DOE has selected several projects for development under the Small-Scale Hydroelectric Power Demonstration Program; two are on New England sites. The first requires major redevelopment of the Great Stone Essex dam on the Merrimack River, in Lawrence, Massachusetts (FERC, 1977). The 130-year-old Essex Dam and the North Canal are recognized historical sites, and the developers will provide public recreation facilities. This facility is being reconstructed by Lawrence Hydroelectric Associates. The site has a 33-foot head, and the powerhouse will contain two 7.1 MW hydroelectric generating units. The estimated capacity factor is 80%. Power will be delivered to NEPCO for distribution to its retail affiliates. The total estimated cost of the facility is $14.7 million. A federal tax-free grant of 15% was provided, and the balance of the financing is being obtained from a consortium of four banks in the northeastern area at an

interest rate of 10.3%. Financial arrangements call for depreciation calculated on a straight-line basis; income and local taxes will be paid; an investment tax credit of 20% is allowed; and the allowed return on investment is 13.3%. Power will be sold at 4.28¢/kWh.

The second project is redevelopment of a hydroelectric project at the sawmill of Brown-New Hampshire Inc. The project is located within the confines of the Brown Company millyards on the Androscoggin River in Berlin, New Hampshire. The dam provides process water for manufacturing purposes, but generation facilities were abandoned and removed in 1961. New generation units will be installed in the existing powerhouse, and they will provide 2.8 MW in five units, at a capacity factor of 83%. This dam has a head of 17.25 feet (FERC, 1978). All of the power generated will be fed into the existing transmission system of Brown Company and will be used to replace the majority (if not all) of the power Brown now purchases for manufacturing. Brown Company is a large industrial customer of PSNH and was generating a portion of the utility's electricity before the rehabilitation scheme was developed. Brown sells power to PSNH in July and December, when the manufacturing facilities are closed down for vacations.

The total estimated cost of the project at the sawmill site is $3.4 million (1978 dollars). Brown received a 25% tax-free grant, and the balance of the investment was financed through private sources. The interest rate cannot be determined from available data. The tax-free grant is to be made available on a "milestone" or progress payment basis (Brown-New Hampshire, Inc., 1979). The first payment reimbursed the Brown Company for 75% of engineering costs, estimated at $105,000. The

second payment will be made when construction is completed. The third payment will be made 2 years after completion. Clearly, a shortcoming of the tax credit is the delay in receipt of payment. The developer must be prepared to absorb the full financing costs at the start of construction. Furthermore, if present worth values are applied in the calculation, the grant is less than 25%.

Brown Company will be required to pay taxes on the full amount of investment above the federal grant. The project is eligible for the investment tax credit of 20%. There is no reimbursement of or allowance on property taxes in a rehabilitation project.

<u>Private Owner-Developer</u>

No information is available on financing arrangements for privately owned facilities, but it is known that small hydro developers have become involved in the New England area. In the absence of specific data, SRI has assumed that the private owner-developer may expect a total return on investment of 9% to 15%. The owner-developer may find it difficult to obtain state permits if the required return is too high. Regulatory bodies invariably place a ceiling upon the return on capital that may be earned. It is assumed that the owner-developer will finance with credit. A possible source of financing is corporation bonds guaranteed by the U.S. government. Such bonds are currently being issued, and they yield 9.25%.* Other corporate bonds are yielding 10%, but they do not have

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*For example, Ship Financing Bonds issued by Trailer Marine Transportation Corporation are guaranteed by the Secretary of Commerce up to 87.5% of the actual cost or depreciated actual cost of the vessel being financed. Monies for payments of guarantees come from a federal ship financing fund or may be borrowed from the U.S. Treasury.

government guarantees. The figure of 9.25% has been chosen as being representative of the costs for a small, private owner-developer under a government-guaranteed program. It is also assumed that the developer would be allowed a 13% return on his investment.

The small owner-developer investing in a rehabilitated hydroelectric project will of course receive a 25% tax-free grant from the U.S. government, which will be paid on a milestone basis as discussed earlier. The developer will also receive an investment tax credit of 20%. The owner-developer will depreciate the equipment, pay income tax (less amortization of the investment tax credit) on profits, and pay local taxes, and insurance. Income tax payments will depend on the tax bracket, but a rate of 45% is considered representative.

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5. ENVIRONMENTAL CONSIDERATIONS

Summary and Conclusions

Because windpower does not require the direct consumption of fossil fuel, it does not contribute to atmospheric or water pollution, nor does it generate solid waste. However, the access roads and transmission lines can disrupt natural surface conditions, the rotor blades can reflect electromagnetic radiation and interfere with microwave or television signals whose paths are thereby interrupted at a cyclic rate, and rotor blades or other parts can fracture and damage property or injure humans and animals within their trajectory. In addition to these known environmental impacts, there has been considerable speculation on the aesthetic acceptability of 300-ft (93-m) diameter wind energy generating stations (WEGS) on 200-ft (62-m) towers dotting the horizon and on the inability of significant numbers of birds to avoid the whirling rotors under conditions of limited or no visibility. SRI concludes that the design and placement of WEGS can reduce the known environmental impacts. However, the speculative impacts and their acceptability as trade-offs for electricity generation from the renewable resource of the wind requires site-specific analyses.

Specific information on the environmental impacts of WEGS is limited, although Battelle, Northwest Laboratories is currently conducting such a study for DOE. For this study, SRI chose to rely heavily on the study of Block Island by DOE. Several sections of this chapter are adapted directly from the report on that study.

New Hampshire Ecology

Even with its high level of industrialization, more than 80% of the land area of New Hampshire is covered by forest. The wooded areas support a varied and flourishing wildlife. Whitetail deer are plentiful, and moose are sometimes seen. Beavers, once almost extinct, have been protected in recent years and are making a gradual comeback. Black bears are relatively numerous, while smaller mammals like rabbit, squirrels, raccoons, foxes, and mink are still plentiful. Bird life, including such species as pheasants, grouse, woodcock, and ducks, is abundant.

North American birds, particularly waterfowl, typically migrate in limited corridors of flight or flyways. Four major flyways are defined by the U.S. Fish and Wildlife Service. New Hampshire is situated near what is termed the Atlantic flyway, and thus is a temporary home for a wide variety of migratory birds.

New Hampshire has six population centers. The heavily wooded White Mountain area in the north is popular with mountain climbers and tourists throughout the year. The lakes region centering on Lake Winnipesaukee is known for summer camps, resorts, and water sports. The seacoast region around Portsmouth, Dover, Exeter, and Hampton has many water-oriented activities. The south-central Merrimack region surrounds the city of Manchester, the most heavily industrialized section. The west-central Dartmouth-Sunapee Lake region embraces many educational institutions and summer homes. The southwestern area around Mount Monadnock is noted for many small industries, the MacDowell Colony (an artists' retreat), and a famous shrine to America's war dead.

The 11% of the state's area represented by White Mountain National Forest is largely uninhabited. The people reside primarily in the southern and southeastern regions, many commuting to jobs in Boston.

New Hampshire has more than 30 ski areas, 200 youth camps, 60 golf courses, 40 state parks, and 800,000 acres of publicly owned forest preserves. Other statistics are shown in Table 5-1.

Potential Environmental Impacts of Construction Activities at the Turbine Site

Site preparation for the wind turbine will require grading and leveling of the tower location, excavation and pouring of the foundation for the tower, and spreading and rolling of crushed stone on the graded surface. Similar preparations will be necessary for each transmission tower site along the line connecting the turbine to the nearest utility power line. Construction of the tower at the turbine site will involve the welding of structural sections and their erection by crane. When assembled, the turbine assembly will be lifted by crane and installed at the top of the tower. Construction time is estimated to be 7 to 9 months.

Site preparation and wind turbine installation will require a soil test rig, a road grader and dump truck, a concrete mixer, a welding rig, and several transport and trailer trucks. A large 85-ton (77.3 mt) capacity conventional crane with a 150-ft (45.7 m) boom will be necessary for installation of the rotor, drive assembly, and generator on the top of the tower. The 85-ton crane is probably the heaviest single piece of equipment that will need to move over the access road.

Table 5-1

NEW HAMPSHIRE STATISTICS

A. Population

Population Growth of New Hampshire 1960-1977

Population 1960	606,921	Population 1970	737,581
Population 1970	737,681	Population 1977 (est.)	849,000
Increase	130,760	Increase	111,419
Percent Increase	21.5%	Percent Increase	15.1%

Source: 1960 and 1970 U.S. Census

Population growth in the 1970-77 period was virtually the same as that of the 1960-70 period. For both periods the State grew by about 2.1% per year.

On the basis of percentage change, New Hampshire was the 9th fastest growing state in the nation during the 1960-1970 period. On the basis of numerical population change, New Hampshire ranked 34th for the same period.

For the 1970-1977 period New Hampshire was the 11th fastest growing state on a percentage basis and ranked 33rd on a numerical basis.

In terms of total population, N.H. ranked 42nd in both 1970 and 1977.

Population Density of New Hampshire

Persons Per:	1960	1970	1977
Acre	0.10	0.12	0.14
Square Mile	65.2	79.3	91.2

Source: Office of Comprehensive Planning

In 1970 New Hampshire ranked 21st in population density, while in 1960 the State ranked 26th.

Major Uses of New Hampshire's Land 1950-1970

Type of Use	1950 Land Area (acres)	1950 % Total	1970 Land Area (acres)	1970 % Total	1950-70 Change	1950-70 % Change
Agricultural	580,265	10.43	430,451	7.74	−149,814	−25.82
Idle	87,774	1.58	104,209	1.87	16,435	18.72
Forested	4,748,379	85.34	4,735,697	85.12	−12,682	−.27
Developed	88,616	1.59	224,102	4.03	135,486	152.89
Other	58,805	1.06	69,380	1.25	10,575	17.98
Total Land	5,563,839	100.00	5,563,839	100.00	0	.00

Source: Institute of Natural and Environmental Resources, UNH, 1975.

Population Projections For New Hampshire

Year	Population	Persons Chg. Per 5 Yrs.	Persons Chg. Per Yr.	% Chg. Per 5 Yrs.	% Chg. Per Yr.
1970	737,681				
1975	825,500	87,319	17,563	11.83	2.36
1980	938,100	113,000	22,600	13.70	2.74
1985	1,022,000	83,900	16,780	8.90	1.78
1990	1,092,000	70,000	14,000	6.85	1.37
1995	1,152,000	60,000	12,000	5.50	1.10
2000	1,207,900	55,900	11,180	4.85	0.97

Source: Office of Comprehensive Planning

Source: New Hampshire Energy Conservation Plan (1979)

A limited number of workers to operate grading equipment, pour the foundation, and install electrical cables will be needed for site preparation. It is estimated that site preparation and wind turbine construction will require a six-man contractor crew for approximately a 9-month period. Short visits by supervisory personnel may also be expected during the installation process.

Motorists are expected to experience only minor inconveniences because of the movement of heavy equipment and trucks on roads near the construction site. The movement of the 70-ft (21.3 m) blade trailer, the 85-ton (77.3 mt) crane and possibly a 35-ton (31.8 mt) crane will cause these temporary inconveniences.

Potential Environmental Impacts of Wind Turbine Structure and Operation

Aesthetics

The distance from which a tall object can be seen over flat terrain is given by $D = 1.2 \sqrt{h}$, where D is distance in nautical miles and h is the object's height in feet. If one considers only the earth's curvature, the blade (in the vertical position) would be visible at a distance of about 22 mi (35.4 km). Because of their size and height, the turbine tower and blades (350 ft, 107 m high) would thus be visible over a wide area, unless some feature of local terrain happens to block the observers' line-of-sight.

Few data on the public's attitude toward the physical presence of large wind turbines are available, but a recent study by the University of Illinois (see DOE, 1978) indicates that the general public considers wind turbine installations more aesthetically acceptable than power

line towers. The study, which included a survey of 1,800 people in Washington, Wyoming, Michigan, Rhode Island, Chicago and New Jersey (at the location of a small wind turbine at Sandy Hook), concluded that a majority "did not seem to have any objections...to locating windmills in scenic areas, on the shores of lakes or oceans, or for that matter even close to their homes."

Historically, windmills have been regarded as being picturesque, but this reaction is generally restricted to the rustic quality of the older windmill structures. A portion of the University of Illinois study discussed the structural aesthetics of six types of wind energy generators: The classical "old Dutch" structures were preferred; columnar tower structures were rated second; and a lattice tower, the type considered in this report, third. The survey respondents were not particularly negative toward any basic design concept.

The most visible component of the structure, and perhaps the least attractive, will be the open-truss tower that supports the turbine. If necessary, this part of the structure can be painted an appropriate color to blend with its background. The tower will appear much like the commonly seen high voltage electric transmission towers. The fact that it does not comprise the total height of the structure and is merely a support for the potentially more attractive component, the cylindrical housing and blades, should somewhat diminish its negative impact.

Because they will be visible from greater distances as well as from partially shielded locations near the wind turbine site, the cylindrical housing and blades should have less negative impact on viewers because of their light color and graceful shape. The visibility of the blades

while rotating will depend on the paint colors used and on the incidental orientation of the plane of rotation to match the wind. Available information on the 175-ft (54.2 m) 1250-kW Smith-Putnam wind turbine, which was installed on a Vermont mountain peak in 1948, indicates that its longer, bulkier blades were visible for 25 mi (40.2 km). The visibility of the blades was probably enhanced by the reflections from their polished stainless steel surfaces, which could have been reduced by a coat of paint.

Wind Turbine Noise

The Federal Noise Control Act of 1973 would prohibit unduly noisy wind turbines; however, noise levels associated with wind turbines are so low that they are difficult to measure because of interference from ambient wind noise. Substantiating this point, noise measurements made at the MOD-0 wind turbine in Plum Brook, Ohio indicated that the slight gear noise and the sound of wind passing over the turbine's blades during operation cannot be perceived over ambient wind sounds by a normal observer at distances greater than 50 ft (15.5 m) from the turbine. Even at the base of the tower supporting the wind turbine, the measured noise level was only 64 dBa, which is below maximum acceptable levels specified for residential areas or work places by existing applicable regulations.

Potential Safety Risks

Although the components of the wind turbine under consideration have been designed to withstand maximum wind speeds of 150 mph (241 km/hr), the remote possibility always exists that a turbine blade might fail or

that the supporting tower might collapse because of extreme wind loading or other severe environmental conditions. To minimize the risk of such blade or tower failure, a variety of safety features have been engineered into the MOD 2 wind turbines. In addition, strict safety precautions and procedures should be instituted, as described below.

General Safety Precautions and Procedures. The tower structure and blades should be inspected at regular intervals by qualified personnel to identify and repair potential structural weaknesses. The turbine should also be inspected immediately following severe wind or storm conditions, and after other unusual conditions, such as earthquakes, nearby landslides, or flooding.

A limited-use exclusion area similar to a power line right-of-way should be maintained around the turbine. Visitor access to this area can be restricted by procedures detailed in a visitor control plan. A 6-7 ft (1.8-2.1 m) exclusion fence erected around the base of the wind turbine would be sufficient to exclude casual observers from any hazard.

Technical personnel should be thoroughly trained to follow safe operating procedures and be fully informed of risks associated with the wind turbine's electrical equipment, rotating machinery, and cable-hung hoist.

Categories of Risk. Three categories of risk have been identified for a large, horizontal-axis wind turbine of the type under consideration here: (1) tower collapse or component blow-off; (2) blade failure; and (3) collision by low-flying aircraft.

Tower Collapse or Component Blow-off--If tower collapse or component blow-off occurs, the wind turbine or one of its components may fall. Because the rotor normally would be feathered and braked before wind speeds exceeded tower design limits, the blade would probably not be thrown any great distance during tower collapse. However, if the rotor breaks in striking the tower or the ground, the area of impact could well increase, depending upon the existing orientation of the rotor and the direction of tower collapse.

Even during periods of extreme wind, the tower is not likely to collapse. Freak gusts, which might far exceed those generally experienced in the area, constitute the only serious hazard. The tower might also collapse if the foundation has been undermined by flooding, ground settling, or an earthquake. Undermining of the foundation would be a relatively gradual process that could be readily noted and corrected during regular maintenance and inspection. Ground acceleration forces that could be expected from a nearby earthquake of up to 7 on the Richter scale are estimated to be less than those associated with strong winds and are not considered a significant hazard with structures of this type. Technical personnel or visitors are in little danger in case of a tower collapse or component blow-off. Such persons would probably not be in exposed areas near the turbine during periods when winds approached or exceeded 150 mph (241 km/hr) or during a tornado warning period. If an earthquake were to occur, the turbine would pose less risk than many other structures to persons nearby because it has high structural strength, relatively low mass, and no loosely attached overhangs or facades, which are the typical sources of injury during earthquakes.

Blade Failure--Computations performed by the NASA-Lewis Research Center (see DOE, 1978) indicate that an unrestrained MOD-OA wind turbine blade might be projected as far as 550 ft (168 m) from the tower base if it broke away from the hub while rotating at its normal 40 rpm and at a near optimum blade throw angle. Pieces of the blade tip might travel even further; however, blade throw distance would be significantly reduced if failure occurred at other than the optimal blade angle.

Automatically monitored sensors should be installed on the wind turbine tower to minimize the risk of blade failure. Any structural problem that might develop during turbine rotation because of an unusual load (such as that caused by structural strain or heavy icing) would be indicated by the excessive vibrations of a dynamic imbalance in the turbine. The machine is designed to shut down automatically before such a problem becomes severe. Remote or automatic restart is not possible according to accepted operating doctrine, which specifies that the wind turbine can only be restarted by resetting the controls at the turbine site.

With the safety and design features that have been incorporated into the MOD-OA wind turbine, blade failure is highly unlikely. Because the turbine will automatically brake to a stop when wind speeds exceed 34 mph (54.4 km/hr) and people are not likely to be near the exclusion radius during high wind or storm conditions, the potential for injury to people is considered to be very limited.

Low-Flying Aircraft--If the turbine is installed where it might pose a hazard to low-flying aircraft, under FAA rules visibility

features such as lighting and paint must be incorporated in the installation to avoid inadvertent collisions.

Effect on Electronic Communications

Large horizontal-axis wind turbine blades may cause interference with high frequency radio waves under some conditions. Television and microwave communications signals may be affected at reception points where the configuration geometry between the wind turbine, transmitter, and receiver is conducive to interference. Such interference can affect the amplitude as well as the intensity of the radio signal. An assessment of the problem of interference at receivers near the site is presented below.

Microwave. A primary criterion used by electronic engineers in determining the potential for a microwave communications interference problem is the ratio of the voltage of the interference signal reflected from the wind turbine rotor (V_{int}) to the voltage of the primary signal received at the microwave antenna (V_{in}). Where $\frac{V_{int}}{V_{in}} = 1\%$, no serious interference problem is likely to occur. Where $\frac{V_{int}}{V_{in}} = 1$ to 5%, there is a potential problem. If the voltage of the interference signal is more than 5% of the voltage received, noticeable interference can be expected. A typical microwave antenna produces a narrow, highly directional beam. The highest levels of interference occur only when the interfering signal is generated within this narrow directional beam, a situation that prudent siting of the turbine system can probably avoid.

Television. A wind turbine illuminated by a direct (primary) signal from a television transmitter results in a secondary signal being scattered off the turbine blades. Because of the rotation of the blades, the net signal field picked up by a television receiver in the vicinity of the wind turbine will be amplitude-modulated. If the modulation is sufficiently strong, it will produce distortion of the signal received. For any given frequency, there is a region around a typical windmill where this distortion can occur. Within this region, interference will increase as the turbine's plane of rotation is oriented such that direct signals which illuminate the blades are reflected directly toward the receiver antenna. Corresponding decreases in interference can be expected as the rotor turns away from the receiver. Consequently, at any given time, reception quality will depend heavily on the orientation of the wind turbine. In areas of fairly constant prevailing winds, this variation of interference patterns will be minimized.

The severity of interference is a function of the distance of the wind turbine from the transmitter, the frequency of the transmitted signal, the location of the receiver relative to the wind turbine and transmitter, and the electronic quality of the receiving antenna and its associated television set. High frequency signals in marginal reception areas give the greatest concern: (1) the roughly circular area of interference around the wind turbine increases as signal frequency increases, and (2) low quality receivers with low signal-to-noise ratios exhibit the greatest degree of image distortion and are affected at greater distances from the turbine.

Because the video portion of the television signal is amplitude-modulated (AM) and the audio portion is frequency-modulated (FM), any AM interfering signal will have its most noticeable effect on the quality of the television picture, but little effect on the audio portion of the program.

When the modulated interference signal reaches or exceeds a threshold of about 10% of the signal received, the image projected on a receiving television screen will be noticeably distorted. At the outer fringes of the interference circle, dark horizontal bars will move vertically on the screen and a "snow" effect will begin. As the interference level increases (as a result of either movement of the rotor plane or a decrease in the distance between the rotor and the receiver), the picture quality will further decrease, and a growing "snow" effect will appear on the tube.

These impacts are experienced most prominently where television reception is by individual antennas, as occurs in many private homes. One way to avoid the interference effects is to install a local cable TV network. This solution has been implemented on Block Island.

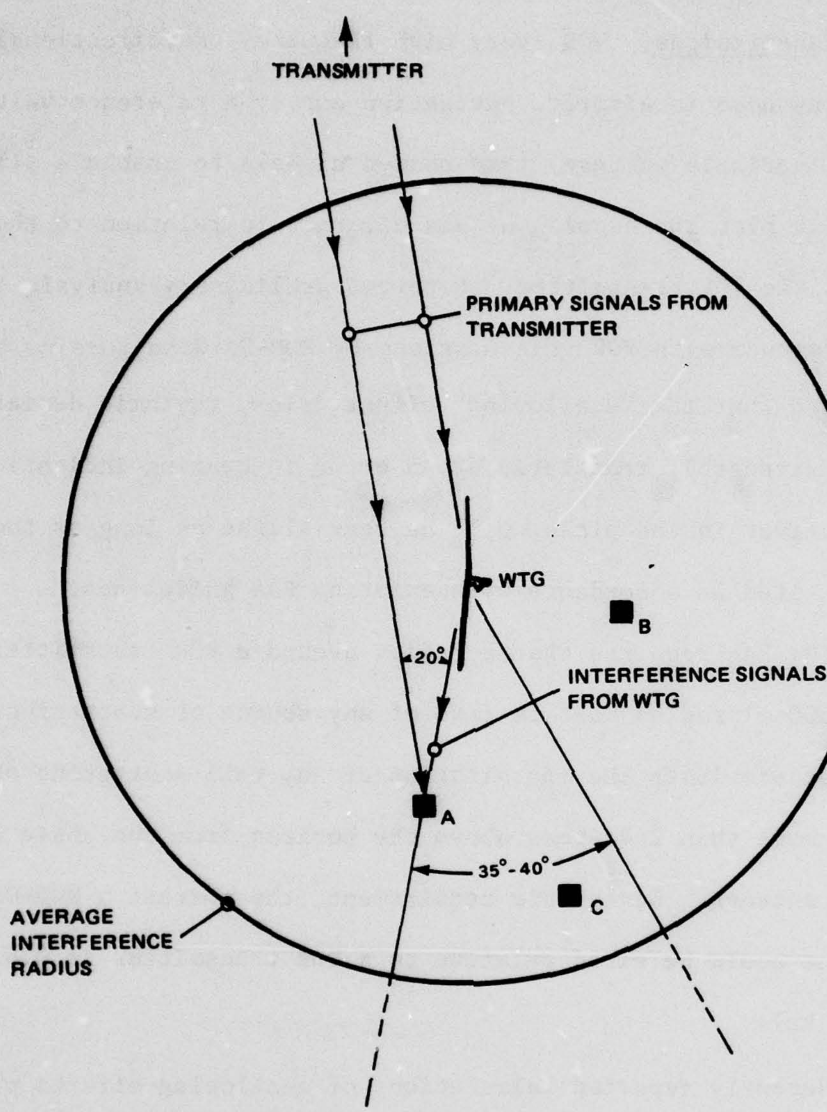
Areas subject to interference can be calculated for each VHF and UHF television channel commonly received in the affected area, and potential reception points within these areas can be identified using local maps, photographs, and observations during site visits.

Directional receiving antennas are generally considered to be effective for alleviating interference caused by wind turbines where the angle formed by the lines of sight from the receiver to the wind turbine and from the receiver to the transmitter is greater than 20

degrees (see Figure 5-1). Using this criterion, directional antennas are ineffective where this angle is less than 20 degrees on either side of the turbine, i.e., for receivers located within a 40-degree shadow cone behind the wind turbine (with respect to the transmitter). As a consequence, the actual percent of local residents who will experience interference is roughly that percent of the total number of receivers located within the interference area that do not have directional antennas. Installing directional antennas on all receivers in the area may reduce the impact, but because of the 40-degree shadow cone (which covers different residential areas depending on the location of the transmitter for each TV channel), there will always remain some unavoidable interference even where directional antennas are used.

Installing directional antennas at the affected homes would not only improve television reception in general, it would also enable those dwellings not now equipped with such antennas to receive UHF broadcasts for the first time.

The FM radio frequencies (88-108 MHz) are between two VHF television bands (Channels 6 and 7). Because frequency modulation caused by rotating wind turbine blades is far less severe than amplitude modulation that distorts video signals, interference to FM radio signals is expected to be very slight. The barely noticeable effect that may occur would only be experienced at receivers located within a few hundred feet of the wind turbine.



Reception Points: A — Receiver at critical 20° angle with respect to transmitter and WTG

B — Directional antenna may eliminate interference

C — Directional antennas will not eliminate interference

SOURCE: U.S. Department of Energy, "Wind Turbine Generator System," Final Environmental Impact Statement (July 1978).

FIGURE 5-1 IDEALIZED GEOMETRY OF RF INTERFERENCE

Impact on Aircraft Navigation

VOR Transmissions. VOR (very high frequency omnidirectional range) transmissions used in aircraft navigation employ a reference voltage signal and AM (variable voltage) time-phased signals to enable a pilot to automatically plot the bearing of his aircraft in relation to the fixed location of the VOR transmitter. Reported preliminary analysis of potential interference with VOR transmissions by MOD-OA wind turbine blades has indicated that the "scalloping" effect (slow, rhythmic deviations in voltage strength), translated as an error in bearing indication at the VOR receiver in the plane, will be very slight as long as the wind turbine is sited in accordance with existing FAA guidelines.

The FAA requires that a region around a VOR transmitter of 1,650-ft (500-m) radius must be free of any source of scattering. The FAA also prohibits the installation of any tall scattering object that rises more than 2 degrees above the horizon from the phase center of any VOR antenna. Given this requirement, the nearest a MOD-OA wind turbine could be sited relative to a VOR transmitter is 0.87 miles (1.4 km).

Recently reported calculations of scalloping effects produced the following data:

	Scalloping (Error in Degrees)	
Distance from VOR	(Static Blade)	(Rotating Blade)
192.0 meters*	5.07°	6.31°
1.4 kilometers	0.78	†
10.0 kilometers	0.11	†

*Within maximum FAA radius

†Negligible

Impact on Aircraft Navigation

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192.0 meters*	5.07°	6.31°
1.4 kilometers	0.78	†
10.0 kilometers	0.11	†

*Within maximum FAA radius

†Negligible

The above data indicate that the VOR bearing errors due to turbine interference decrease dramatically with increased distance from the VOR transmitter, and that bearing error is greater when the blades are stationary (a relatively rare mode) than when the turbine is operating. The lesser effect when the blades are rotating is due to the distribution of the scattered signal over a band of frequencies. The VOR receiver is sensitive only to 30-Hz modulated signals, and when the rotor is stationary, the 30-Hz modulated signals are directly reflected without frequency distribution.

Although the FAA has as yet set no specific limits for scalloping, reports of analyses on which future FAA guidelines may be based indicate that scalloping of 1.0° or less is acceptable, and that bearing deviations of up to 5.0° may be tolerable under certain conditions. Because the rotating blades (the only feature of a wind turbine that makes it unique to the view of a VOR receiver) have less impact than stationary structures, it appears that existing FAA guidelines will ensure that the impact of the wind turbine upon VOR transmissions will be small. The open truss-type tower used by the wind turbine is similar to the radio towers and high voltage transmission towers for which the FAA regulations were designed.

<u>ADF Transmission</u>. Automatic Direction Finding (ADF) transmitters operating at 116 kHz are installed at some airports for use in aircraft navigation. The turbine should be located so as to minimize any

interference with the ADF transmissions and aircraft approach patterns. FAA height standards regulate all physical structures located within 20,000 ft (6,300 m) of an airport.

DME and TACAN Transmissions. Distance Measuring Equipment (DME) and Tactical Air Navigation (TACAN) systems use pulsed FM signals to enable aircraft receiving units to determine the plane's distance from the transmitter. Because wind turbine blades produce only slight frequency modulation effects, even within several hundred feet of a transmission source, no interference with these transmissions is anticipated.

Effects on Animal Populations

Terrestrial Wildlife. Because operating a wind turbine causes little noise and no chemical pollution, the effects on terrestrial species will be small. Battelle studies (see DOE, 1978) indicate that animals near the wind turbine will probably be neither attracted nor repelled by the turbine noise. In addition, studies by others to develop a complete noise profile for turbines, including infrasound and ultrasound, are currently under way. A review of these results will allow for consideration of any unusual sound levels in ranges not audible to humans that could possibly have an impact on animals.

Birds. New Hampshire lies near the Atlantic flyway, a flight corridor for migrating North American bird species. The Rare and Endangered Species Act of 1973 restricts any project that might interfere with the migratory path of endangered birds.

Wind turbine towers and rotating turbine blades are potential hazards to birds. Because birds are apparently able to learn to avoid obstacles placed in their home territory, the turbine presents a danger primarily to migrant birds, particularly nocturnal migrants flying at or below 350 ft (109 m). Although most migratory flights at night take place at about 3,000 ft (930 m), great variations occur, depending on weather conditions, terrain, and bird species. Birds are believed to fly higher on clear nights, but not necessarily at the same height for all stages of the flight. A radar study of nocturnal migrants (see DOE report, 1978) reported that 90% of the birds flew below 5,000 ft (1,520 m) and 75% below 3,000 ft (930 m). Another study, also using radar, had similar results (90% below 5,000 ft), but also reported occasional shorebirds up to 20,000 ft (6,300 m). Storms or overcast conditions will sometimes force birds below their normal cruising altitude or force them to take shelter on the surface.

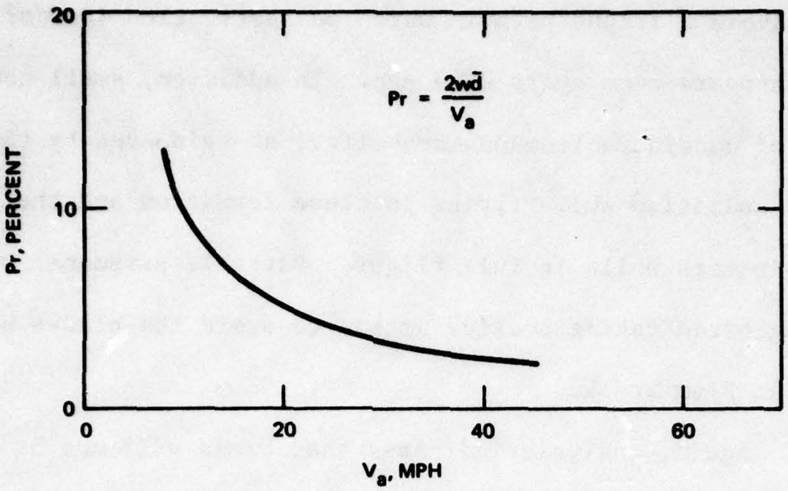
Most smaller insectivorous bird species migrate at night, resting and feeding by day, with long stopovers at intermediate stations, either for replenishing depleted energy or waiting for more favorable flying conditions.

Collisions of nocturnal migrants with the 200-ft (62 m) tower are considered improbable. A comprehensive radar survey of birds passing over Cape Cod (see DOE report, 1978) indicated that most types of birds in that nearby sector of the Atlantic flyway migrate at an altitude of 1,500 to 2,500 ft (460-760 m) above ocean or land. The study concluded that only 10 to 20% of the birds were flying below 600 ft (183 m). This finding seems to be substantiated by recent

studies (see DOE, 1978) that indicate that most migrant songbirds in the eastern United States fly at 500 to 1,000 ft (155 to 310 m) above ground level--well above the wind turbine tower.

The danger of the tower to local bird species and diurnal migrants (flying at elevations below 200 ft or 62 m) is also considered to be small. A reported literature survey revealed that almost all significant bird kills occur at night, when birds cannot see latticework towers and guy wires, or are confused by warning lights or beacons. The number of bird kills is estimated to be directly proportional to the height of the tower involved. However, all such reports have been concerned with towers and buildings at least 400 ft (124 m) high or far-reaching light beams such as those produced by ceilometers or lighthouses.

In the MOD-OA turbine, the blades are the most predominant component, covering a relatively large swept area 125 ft (38 m) in diameter. An analysis by Battelle (see DOE, 1978) indicates that birds will not be swept away from the blades, because the momentum of a flying bird is sufficient to withstand the turning forces imposed by the rotor on the air stream. Nevertheless, the statistical likelihood of a bird flying through the area swept by the rotor and actually striking a blade is quite low. Even when a bird passes directly through the area swept by the blades, the probability of the bird striking a blade is a function of the width and speed of the blades (rotor solidity) and the speed of the bird's flight. Figure 5-2 shows the probability curve of the likelihood of birds colliding with the MOD-OA blades. The potential for



SOURCE: U.S. Department of Energy, "Wind Turbine Generator System," Final Environmental Impact Statement (July 1978).

FIGURE 5-2 PROBABILITY OF A BIRD STRIKING THE ROTOR BLADES AS A FUNCTION OF ITS AXIAL VELOCITY

collision is greatest (13%) for a cruising or slow-flying bird (8 mph, 13 km/hr) and decreases to 4% at 30 mph (48 km/hr), the typical speed of songbirds during migration.

Though the probability of collision by a lone bird flying directly into the rotor disk is relatively low, the probability increases when a large number of birds are involved, particularly when the flock passes through the blades at an angle. If a flock of 50 songbirds were to pass head-on through the disk at an average speed of 30 mph (48 km/hr), on a statistical basis two birds could be expected to collide with the rotor. The number of collisions would increase as a function of the angle of the birds' descent or ascent.

Reported behavioral studies of bird reactions to turbine blades rotating at relatively slow velocity are now being carried out by Battelle Memorial Institute (see DOE, 1978). Daylight-flying birds

tend to avoid a flight path in which an obstruction (one of the two blades) appears once every 0.75 sec. In addition, small songbirds are capable of considerable maneuverability, as evidenced by their ability to avoid collision while flying in close formation and their ability to feed on insects while in full flight. Battelle personnel have reported observing birds taking evasive action to avoid the blades of the MOD-0 turbine at Plum Brook.

Again, analysis indicates that birds will not be swept by the airstream of the rotor, and so will not be "drawn into" the blades.

Insects. Insects and other small invertebrates are present in the air above both land and water habitats. No specific studies have been conducted on aerial distribution of arthropods relative to wind turbines; however, a reported vertical profile suggests that arthropods have been collected thousands of feet above the ground, but that the majority of these organisms are within 100 ft (30 m) of the ground.

The absolute distribution and abundance of arthropods aloft differs seasonally, daily, and even hourly. The complex interactions of wind turbulence, light, temperature, relative humidity, and other physical properties of air interact in different ways to maintain a fluctuating profile and movement pattern of arthropods. In temperate zones, such as the New Hampshire area, the greatest population densities occur in the late spring and summer and are small in the winter.

Observations at a 100-kW wind turbine revealed that because most insects are small enough to be turned by the streamlines, their probability of impact is less than for birds. For insects flying at

speeds of 11.5 ft/sec (3.5 m/sec) the probability of striking the blades is approximately 8%. The probability decreases with increased flight speeds. Thus, the number of insects that will strike the rotor blades of a wind turbine similar to the 100-kW design will be less than 10% of those passing horizontally through the rotor-swept airspace.

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6. USER REQUIREMENTS

Summary and Conclusions

The Portsmouth Shipyard currently uses 5 to 11 MW of electrical power in its ordinary operations of repairing and overhauling nuclear submarines. Residual fuel oil is used to raise 600 psig steam that is first used in double extraction turbines to generate 3 to 4 MW of this power and then to supply the process steam, space heating, and hot water requirements of the yard. This cogeneration of electricity and steam uses the fuel much more efficiently. However, the amount of steam that is needed determines to a great extent the amount of electricity that the yard generates. The balance of the Shipyard's electrical power, 2 to 7 MW, is purchased from Public Service of New Hampshire (PSNH). The yard is a significant industrial customer of PSNH, even though its requirement consumes only a small part of that utility's 1,300 MW of installed capacity.

The Shipyard is located in Kittery, Maine, and is a customer of PSNH by historical accident. It could become a customer of Central Maine Power Company (CMPC), the franchise utility for Kittery, at some future date.

To place the Navy's needs in the context of electricity in the region as a whole, SRI examined the in-place and projected generating capacity of PSNH, CMPC, and a number of other utilities and groups. These included the New England Electric System (NEES), a utility that has

announced its favorable attitude toward the purchase of energy from wind and other renewable energy sources that save fuel, and the New England Power Pool (NEPOOL), a utility organization that coordinates the schedules for construction and operation of generating and transmission units in the New England grid to achieve the lowest cost electricity consistent with adequate reliability for the whole system. The capacity of these groups was compared with projections of electricity demand on these facilities. SRI's projections of demand and the announced construction plans for new generating units suggest that the New England grid as a whole will have a capacity deficit in the future. Reliability of purchased electricity service to the Shipyard, however, will not be improved by Navy participation in WEGS purchases or installations in the Mt. Washington area.

The Shipyard is purchasing its power from PSNH at a price that is based on the average of a relatively low-cost generating mix. This price is lower than the projected cost of electricity from WEGS, so the Navy has no economic incentive to support windpower development.

<u>NEPOOL</u>

If the Navy or other nonutility owners/users of WEGS are separated from their machine sites by significant distances, WEGS operators will need to have the utilities wheel, or transmit, the power over their transmission and distribution lines. The utilities will also be needed to purchase the surplus electricity that can be generated or to exchange windpower received during some hours, days, or seasons for power delivered at other times to meet the demand of the WEGS owners. The extent to which the utilities can perform these indispensable functions in windpower development will depend on their physical plants and the degree to

which they are utilized. SRI's examination of the present and projected supply and demand status of NEPOOL is intended to provide some measure of the ability of the system to absorb windpower.

The analyses that follow use announced construction plans for new generating and transmission facilities. Proposed or mentioned units, such as Seabrook 3, whose construction date has not been set are not included. The dates for starting units now under construction, such as Seabrook 1 and 2, are taken from the most recent official announcements in SRI's files.

SRI assumes that fossil-fired units will be retired after about 35 years of service, even though the units are usually capitalized over a 30-year period.

SRI's own projections of load growth are used in these analyses, and these projections are generally lower than those from other sources. The primary reason for the differences is SRI's judgment of the amount of energy conservation that can be expected to accompany increasing prices of energy. The reader is cautioned to avoid comparison of these analyses with those of the utilities, public utility commissions, and energy commissions or agencies until it has been adequately established that the differences in significant assumptions are known and understood.

Table 6-1 provides a broad measure of the generating mix of the New England states, according to fuel type. Nearly half (47.7%) of the capacity is oil-fired, and replacement of any part of its energy output with WEGS electricity will have a desirable effect on oil consumption in the region.

Table 6-1

NEW ENGLAND REGION:
1977 AVAILABLE CAPACITY BY FUEL TYPE
FOR MAJOR UTILITIES*

Available capacity ($MW \times 10^3$)	New England	Connecticut	Maine	Massachusetts	New Hampshire	Vermont
Entitlements	0.1	-	-	-	-	0.1
Nuclear	4.2	1.7	0.4	1.7	0.1	0.3
Coal	2.3	-	-	1.8	0.5	-
Oil	9.6	3.6	0.4	4.9	0.6	0.1
Gas	-	-	-	-	-	-
Hydropower	1.1	0.1	0.2	0.6	0.1	0.1
Pumped storage	1.6	0.8	-	0.8	-	-
Gas turbine	1.2	0.4	0.1	0.5	0.1	0.1
Total	20.1	6.6	1.1	10.3	1.4	0.7
Proportion of capacity in each fuel type (%)						
Entitlement	0.5	-	-	-	-	14.3
Nuclear	20.9	25.8	36.4	16.5	7.1	42.9
Coal	11.4	-	-	17.5	35.7	-
Oil	47.7	54.5	36.4	47.6	42.9	14.3
Gas	-	-	-	-	-	-
Hydropower	5.5	1.5	18.2	5.8	7.2	14.3
Pumped storage	8.0	12.1	-	7.8	-	-
Gas turbine	6.0	6.1	9.0	4.8	7.1	14.2
Total	100.0	100.0	100.0	100.0	100.0	100.0

*Utility capacity includes participation in both in-state and out-of-state Yankee units.

Table 6-2 summarizes SRI's projections of the net effects of load growth, new construction, and retirements. The capacity deficits that are projected must be compensated for by the construction of new generating units, but the construction startup dates for such units have not yet appeared in print. Windpower cannot be counted on as a source of new capacity because of wind variations, but the projected capacity deficits will probably make windpower more acceptable to the affected utilities. It might even be actively sought by some to supplement their own generation.

The utilities do not generally report the kind of service assigned to each generating unit, and it is not unusual to transfer units from one service to another as the units age and the needs change, for example, as older base-load units are derated and used for intermediate service. Table 6-3 is SRI's estimate of present service assignments and projections of these assignments. The intermediate service units are cycled at hourly rates that approximate the diurnal variations in the wind, so they are the units most likely to be supplanted by WEGS. Base-load service is at an essentially constant output, and peak-load service must accommodate real-time variations in demand, so units in these services would not be appropriate candidates for replacements by facilities dependent on wind variations. The present intermediate service uses about 4,020 MW of the NEPOOL system generating capacity, and SRI projects an increase to 12,150 MW by 2001. Tables 6-4 through 6-9 give SRI's estimates of the present assignment and projections of the capacity requirements for the individual New England states and the major utilities within these states.

Table 6-2

SUMMARY OF CAPACITY REQUIREMENTS FOR MAJOR UTILITIES IN THE NEW ENGLAND STATES*
(Thousands of Megawatts)

	New England Total†	Total Representative Utilities Analyses	Connecticut	Maine	Massachusetts	New Hampshire	Vermont
Installed Capacity‡							
1977	20.8	19.9	6.6	1.1	10.3	1.4	0.5
1986	26.6	24.5	7.0	2.1	12.8	1.8	0.8
1989	28.1	25.0§	7.4	2.0	13.1	1.7	0.8
2001	26.6	23.6§	7.0	1.9	12.4	1.5	0.8
Required Capacity							
1986	28.2	25.2	7.9	1.6	12.4	2.3	1.0
1989	30.3	30.2	11.4	1.7	13.6	2.5	1.0
2001	38.8	39.0	14.6	2.4	17.3	3.2	1.5
Surplus or (deficit)§■							
1986	(1.6)	(0.7)§	(0.9)	0.5	0.4	(0.5)	(0.2)
1989	(2.2)	(5.2)‡	(4.0)	0.3	(0.5)	(0.8)	(0.2)
2001	(12.2)	(15.3)§	(7.6)	(0.4)	(4.9)	(1.7)	(0.7)

*Rhode Island is largely served by out-of-state utilities.

†Includes Rhode Island.

‡Estimates are based on current announcements and include joint ownership units.

§Utility capacity totals are affected by announced sales of participation to unknown buyers.

■Figures in parentheses are deficits.

	Connecticut Utilities				Maine Utilities				Massachusetts Utilities			
	Total	Base	Int.	Peak	Total	Base	Int.	Peak	Total	Base	Int.	Peak
1977												
Installed capacity*	6.6	3.8	1.4	1.4	1.1	0.6	0.3	0.2	10.32	6.59	2.10	1.63
1986												
Required for utility load	7.9	3.9	2.4	1.6	1.6	0.8	0.5	0.3	12.4	6.25	3.93	2.22
Capacity												
Entitlements	-	-	-	-	-	-	-	-	-	-	-	-
Installed capacity												
Nuclear	2.56	2.56	-	-	0.5	0.5	-	-	4.71	4.71	-	-
Coal	-	-	-	-	0.5	0.5	-	-	1.76	1.12	0.64	-
Oil	2.96	1.64	0.80	0.52	0.7	0.4	0.1	0.2	4.41	2.22	1.32	0.87
Gas	-	-	-	-	-	-	-	-	-	-	-	-
Hydropower	0.11	-	-	0.11	0.4	0.2	0.1	0.1	0.62	0.02	0.53	0.07
Pumped storage	0.88	-	-	0.88	-	-	-	-	0.77	-	-	0.77
Gas turbine	0.44	-	-	0.44	0.04	-	-	0.04	0.53	-	-	0.53
Total available capacity	6.95	4.20	0.80	1.95	2.14	1.6	0.2	0.34	12.8	8.07	2.49	2.24
Surplus/(deficit)†	(0.95)	0.30	(1.60)	0.35	0.54	0.8	(0.3)	0.04	0.4	1.82	(1.44)	0.02
1989												
Required for utility load	11.4	5.6	3.6	2.2	1.7	0.9	0.5	0.3	13.62	6.76	4.34	2.52
Capacity												
Entitlements	-	-	-	-	-	-	-	-	-	-	-	-
Installed capacity												
Nuclear	3.2	3.2	-	-	0.5	0.5	-	-	6.10	6.10	-	-
Coal	-	-	-	-	0.5	0.5	-	-	1.24	1.12	0.12	-
Oil	2.74	1.64	0.42	0.68	0.6	0.4	-	0.2	3.89	2.24	1.22	0.43
Gas	-	-	-	-	-	-	-	-	-	-	-	-
Hydropower	0.11	-	-	0.11	0.4	0.2	0.1	0.1	0.62	0.02	0.53	0.07
Pumped storage	0.88	-	-	0.88	-	-	-	-	0.76	-	-	0.76
Gas turbine	0.44	-	-	0.44	0.04	-	-	0.04	0.53	-	-	0.53
Total available capacity	7.37	4.84	0.42	2.11	2.04	1.6	0.1	0.34	13.14	9.48	1.87	1.79
Surplus/(deficit)†	(4.03)	(0.76)	(3.18)	(0.09)	0.34	0.7	(0.4)	0.04	(0.48)	2.72	(2.47)	(0.73
2001												
Required for utility load	14.6	7.2	4.6	2.8	2.4	1.2	0.7	0.5	17.26	8.58	5.35	3.33
Capacity												
Entitlements	-	-	-	-	-	-	-	-	-	-	-	-
Installed capacity												
Nuclear	3.95	3.95	-	-	0.6	0.6	-	-	6.48	6.48	-	-
Coal	-	-	-	-	0.5	0.5	-	-	1.12	1.12	-	-
Oil	1.64	1.64	-	-	0.4	0.4	-	-	2.88	2.24	0.54	0.1
Gas	-	-	-	-	-	-	-	-	-	-	-	-
Hydropower	0.11	-	-	0.11	0.4	0.2	0.1	0.1	0.62	-	0.38	0.2
Pumped storage	0.88	-	-	0.88	-	-	-	-	0.76	-	-	0.7
Gas turbine	0.44	-	-	0.44	0.04	-	-	0.04	0.53	-	-	0.5
Total available capacity	7.02	5.59	-	1.43	1.94	1.7	0.1	0.14	12.39	9.84	0.92	1.6
Surplus/(deficit)†	(7.58)	(1.61)	(4.6)	(1.37)	(0.46)	0.5	(0.6)	(0.36)	(4.87)	1.26	(4.43)	(1.7

*Includes Yankee units.

†Figures in parentheses are projected deficits.

…sachusetts Utilities				New Hampshire Utilities				Vermont Utilities				Total			
l	Base	Int.	Peak	Total	Base	Int.	Peak	Total	Base	Int.	Peak	Total	Base	Int.	Peak
2	6.59	2.10	1.63	1.4	0.9	0.2	0.3	0.52	0.39	0.02	0.11	19.94	12.28	4.02	3.64
	6.25	3.93	2.22	2.3	1.2	0.7	0.4	1.0	0.5	0.3	0.2	25.2	12.65	7.83	4.72
	-	-	-	-	-	-	-	0.14	0.14	-	-	0.14	0.14	-	-
1	4.71	-	-	0.56	0.56	-	-	0.44	0.44	-	-	8.77	8.77	-	-
5	1.12	0.64	-	0.46	0.35	0.11	-	-	-	-	-	2.73	1.98	0.75	-
1	2.22	1.32	0.87	0.63	0.43	-	0.20	0.03	0.02	-	0.01	8.72	4.70	2.22	1.80
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	0.02	0.53	0.07	0.06	-	0.06	-	0.11	0.07	0.01	0.03	1.30	0.29	0.70	0.31
7	-	-	0.77	-	-	-	-	-	-	-	-	1.65	-	-	1.65
3	-	-	0.53	0.10	-	-	0.10	0.11	-	-	0.11	1.22	-	-	1.22
	8.07	2.49	2.24	1.81	1.34	0.17	0.30	0.83	0.67	0.01	0.15	24.53	15.88	3.67	4.98
	1.82	(1.44)	0.02	(0.49)	0.14	(0.53)	(0.10)	(0.17)	0.17	(0.29)	(0.05)	(0.67)	3.23	(4.16)	0.26
2	6.76	4.34	2.52	2.5	1.2	0.8	0.5	1.0	0.5	0.3	0.2	30.22	14.96	9.54	5.72
	-	-	-	-	-	-	-	0.14	0.14	-	-	0.14	0.14	-	-
	6.10	-	-	0.56	0.56	-	-	0.44	0.44	-	-	10.80	10.80	-	-
	1.12	0.12	-	0.46	0.35	0.11	-	-	-	-	-	2.20	1.97	0.23	-
	2.24	1.22	0.43	0.47	0.41	-	0.06	0.03	0.02	-	0.01	7.73	4.71	1.64	1.38
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	0.02	0.53	0.07	0.06	-	0.06	-	0.11	0.04	0.04	0.03	1.30	0.26	0.73	0.31
	-	-	0.76	-	-	-	-	-	-	-	-	1.64	-	-	1.64
	-	-	0.53	0.10	-	-	0.10	0.11	-	-	0.11	1.22	-	-	1.22
	9.48	1.87	1.79	1.65	1.32	0.17	0.16	0.83	0.64	0.04	0.15	25.03	17.88	2.60	4.55
)	2.72	(2.47)	(0.73)	(0.85)	0.12	(0.63)	(0.34)	(0.17)	0.14	(0.26)	(0.05)	(5.19)	2.92	(6.94)	(1.17)
	8.58	5.35	3.33	3.2	1.6	1.0	0.6	1.5	0.7	0.5	0.3	38.96	19.28	12.15	7.53
	-	-	-	-	-	-	-	0.14	0.14	-	-	0.14	0.14	-	-
	6.48	-	-	0.56	0.56	-	-	0.44	0.44	-	-	12.03	12.03	-	-
	1.12	-	-	0.35	0.35	-	-	-	-	-	-	1.97	1.97	-	-
	2.24	0.54	0.10	0.43	0.43	-	-	0.03	0.02	-	0.01	5.38	4.73	0.54	0.11
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	0.38	0.24	0.06	-	0.06	-	0.11	0.04	0.01	0.06	1.30	0.24	1.55	0.51
	-	-	0.76	-	-	-	-	-	-	-	-	1.64	-	-	1.64
	-	-	0.53	0.10	-	-	0.10	0.11	-	-	0.11	1.22	-	-	1.22
	9.84	0.92	1.63	1.50	1.34	0.06	0.10	0.83	0.64	0.01	0.18	23.68	19.11	1.09	3.48
	1.26	(4.43)	(1.70)	(1.70)	(0.26)	(0.94)	(0.50)	(0.67)	(0.06)	(0.49)	(0.12)	(15.28)	(0.17)	(11.06)	(4.05)

Table 6-3

SUMMARY OF CAPACITY REQUIREMENTS
FOR MAJOR UTILITIES IN THE NEW ENGLAND REGION
(Thousands of Megawatts)

1 2

Table 6-4

CAPACITY REQUIREMENTS FOR MAJOR UTILITIES IN CONNECTICUT (Thousands of Megawatts)

	Northeast Utilities (Connecticut Light & Power)				Northeast Utilities (Hartford Electric Light)				United Illuminating Company				Total of Foregoing Utilities				
	Total	Base	Int.	Peak	Total	Base	Int.	Peak	Total	Base	Int.	Peak	Total	Base	Int.	Peak	State Total
1977																	
Installed capacity*	3.2	1.8	0.7	0.7	1.9	1.0	0.4	0.5	1.5	1.0	0.3	0.2	6.6	3.8	1.4	1.4	6.4
1986																	
Required for load	3.9	1.9	1.2	0.8	2.4	1.2	0.7	0.5	1.6	0.8	0.5	0.3	7.9	3.9	2.4	1.6	7.0
Capacity																	
Entitlements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Installed capacity																	
Nuclear	1.4	1.4	-	-	0.76	0.76	-	-	0.40	0.40	-	-	2.56	2.56	-	-	
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Oil	1.0	0.4	0.3	0.3	0.82	0.40	0.24	0.18	1.14	0.84	0.26	0.04	2.96	1.64	0.80	0.52	
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Hydropower	0.1	-	-	0.1	0.01	-	-	0.01	-	-	-	-	0.11	-	-	0.11	
Pumped storage	0.6	-	-	0.6	0.28	-	-	0.28	-	-	-		0.88	-	-	0.88	
Gas turbine	0.2	-	-	0.2	0.22	-	-	0.22	0.02	-	-	0.02	0.44	-	-	0.44	
Total available capacity	3.3	1.8	0.3	1.2	2.09	1.16	0.24	0.69	1.56	1.24	0.26	0.06	6.95	4.20	0.80	1.95	7.0
Surplus/(deficit)†	(0.6)	(0.1)	(0.9)	0.4	(0.31)	(0.04)	(0.46)	0.19	(0.04)	0.44	(0.24)	(0.24)	(0.95)	0.30	(1.60)	0.35	-0-
1989																	
Required for load	7.3	3.6	2.3	1.4	2.5	1.2	0.8	0.5	1.6	0.8	0.5	0.3	11.4	5.6	3.6	2.2	7.3
Entitlements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Installed capacity																	
Nuclear	1.8	1.8	-	-	1.0	1.0	-	-	0.40	0.40	-	-	-	-	-	-	
Coal	-	-	-	-	-	-	-	-	-	-	-	-	3.2	3.2	-	-	
Oil	0.9	0.4	-	0.5	0.82	0.40	0.24	0.18	1.02	0.84	0.18	-	2.74	1.64	0.42	0.68	
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Hydropower	0.1	-	-	0.1	0.01	-	-	0.01	-	-	-	-	0.11	-	-	0.11	
Pumped storage	0.6	-	-	0.6	0.28	-	-	0.28	-	-	-	-	0.88	-	-	0.88	
Gas turbine	0.2	-	-	0.2	0.22	-	-	0.22	0.02	-	-	0.02	0.44	-	-	0.44	
Total available capacity	3.6	2.2	-	1.4	2.33	1.40	0.24	0.69	1.44	1.24	0.18	0.02	7.37	4.84	0.42	2.11	6.8
Surplus/(deficit)†	(3.7)	(1.4)	(2.3)	-	(0.17)	0.20	(0.56)	0.19	(0.16	0.44	(0.32)	(0.28)	(4.03)	(0.76)	(3.18)	(0.09)	(0.5)
2001																	
Required for load	9.3	4.6	2.9	1.8	3.2	1.6	1.0	0.6	2.1	1.0	0.7	0.4	14.6	7.2	4.6	2.8	9.3
Entitlements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Installed capacity																	
Nuclear	2.3	2.3	-	-	1.25	1.25	-	-	0.40	0.40	-	-	3.95	3.95	-	-	
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Oil	0.4	0.4	-	-	0.40	0.40	-	-	0.84	0.84	-	-	1.64	1.64	-	-	
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Hydropower	0.1	-	-	0.1	0.01	-	-	0.01	-	-	-	-	0.11	-	-	0.11	
Pumped storage	0.6	-	-	0.6	0.28	-	-	0.28	-	-	-	-	0.88	-	-	0.88	
Gas turbine	0.2	-	-	0.2	0.22	-	-	0.22	0.02	-	-	0.02	0.44	-	-	0.44	
Total available capacity	3.6	2.7	-	0.9	2.16	1.65	-	0.51	1.26	1.24	-	0.02	7.02	5.59	-	1.43	5.6
Surplus/(deficit)†	(5.7)	(1.9)	(2.9)	(0.9)	(1.04	0.05	(1.0)	(0.09)	(0.84)	0.24	(0.7)	(0.38)	(7.58)	(1.61)	(4.6)	(1.37)	(3.7)

*Includes participation in Yankee units.
†Figures in parentheses indicate a projected deficit.

Table 6-5

CAPACITY REQUIREMENTS FOR MAJOR UTILITIES IN MAINE
(Thousands of Megawatts)

	Central Maine Power Co.				
	Total	Base	Int.	Peak	State Total
1977					
Installed* capacity	1.1	0.6	0.3	0.2	1.7
1986					
Required for load	1.6	0.8	0.5	0.3	2.2
Capacity					
Entitlements	-	-	-	-	-
Installed capacity					
Nuclear	0.5	0.5	-	-	
Coal	0.5	0.5	-	-	
Oil	0.7	0.4	0.1	0.2	
Gas	-	-	-	-	
Hydropower	0.4	0.2	0.1	0.1	
Pumped storage	-	-	-	-	
Gas turbine	0.04	-	-	0.04	
Total available capacity	2.14	1.6	0.2	0.34	2.7
Surplus/(deficit)†	0.54	0.8	(0.3)	0.04	0.5
1989					
Required for load	1.7	0.9	0.5	0.3	2.4
Entitlements	-	-	-	-	-
Installed capacity					
Nuclear	0.5	0.5	-	-	
Coal	0.5	0.5	-	-	
Oil	0.6	0.4	-	0.2	
Gas	-	-	-	-	
Hydropower	0.4	0.2	0.1	0.1	
Pumped storage	-	-	-	-	
Gas turbine	0.04	-	-	0.04	
Total available capacity	2.04	1.6	0.1	0.34	2.7
Surplus/(deficit)†	0.34	0.7	(0.4)	0.04	0.3
2001					
Required for load	2.4	1.2	0.7	0.5	3.1
Entitlements	-	-	-	-	-
Installed capacity					
Nuclear	0.6	0.6	-	-	
Coal	0.5	0.5	-	-	
Oil	0.4	0.4	-	-	
Gas	-	-	-	-	
Hydropower	0.4	0.2	0.1	0.1	
Pumped storage	-	-	-	-	
Gas turbine	0.04	-	-	0.04	
Total available capacity	1.94	1.7	0.1	0.14	2.5
Surplus/(deficit)†	(0.46)	0.5	(0.6)	(0.36)	(0.6)

*Includes Yankee units.

†Figures in parentheses indicate projected deficits.

	Boston Edison Co.				Western Massachusetts (Northeast Utilities)				Eastern Utilities (Blackstone; Brockton; Fall River; Montaup)				New England Gas El (Cambridge; New Bedford; Canal Electri		
	Total	Base	Int.	Peak	Total	Base	Int.	Peak	Total	Base	Int.	Peak	Total	Base	Int.
1977															
Installed capacity*	3.1	2.4	0.4	0.3	1.0	0.4	0.3	0.3	0.71	0.48	0.19	0.04	1.10	0.90	0.07
1986															
Required for load	3.6	1.8	1.1	0.7	1.4	0.7	0.5	0.2	1.0	0.5	0.3	0.2	0.7	0.4	0.2
Capacity															
Entitlements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Installed capacity															
Nuclear	1.4	1.4	-	-	0.52	0.52	-	-	0.66	0.66	-	-	0.32	0.32	-
Coal	-	-	-	-	-	-	-	-	0.12	-	0.12	-	-	-	-
Oil	1.8	0.6	0.8	0.4	0.16	-	0.11	0.05	0.34	0.26	-	0.08	0.91	0.82	-
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydropower	-	-	-	-	0.11	-	0.05	0.06	-	-	-	-	-	-	-
Pumped storage	-	-	-	-	0.17	-	-	0.17	-	-	-	-	-	-	-
Gas turbine	0.2	-	-	0.2	0.14	-	-	0.14	0.04	-	-	0.04	0.11	-	-
Total available capacity	3.4	2.0	0.8	0.6	1.10	0.52	0.16	0.42	1.16	0.92	0.12	0.12	1.34	1.14	-
Surplus/(deficit)†	(0.2)	0.2	(0.3)	(0.1)	(0.30)	(0.18)	(0.34)	0.22	0.16	0.42	(0.18)	(0.08)	0.64	0.74	(0.2)
1989															
Required for load	3.9	1.9	1.2	0.8	1.6	0.8	0.5	0.3	1.2	0.6	0.4	0.2	0.8	0.4	0.3
Entitlements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Installed capacity															
Nuclear	1.4	1.4	-	-	0.68	0.68	-	-	0.74	0.74	-	-	0.41	0.41	-
Coal	-	-	-	-	-	-	-	-	0.12	-	0.12	-	-	-	-
Oil	1.6	0.6	0.7	0.3	0.11	-	0.11	-	0.28	0.28	-	-	0.87	0.82	-
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydropower	-	-	-	-	0.11	-	0.05	0.06	-	-	-	-	-	-	-
Pumped storage	-	-	-	-	0.16	-	-	0.16	-	-	-	-	-	-	-
Gas turbine	0.2	-	-	0.2	0.14	-	-	0.14	0.04	-	-	0.04	0.11	-	-
Total available capacity	3.2	2.0	0.7	0.5	1.20	0.68	0.16	0.36	1.18	1.02	0.12	0.04	1.39	1.23	-
Surplus/(deficit)†	(0.7)	0.1	(0.5)	(0.3)	(0.40)	(0.12)	(0.34)	0.06	(0.02)	0.42	(0.28)	(0.16)	0.59	0.83	(0.3)
2001															
Required for load	4.8	2.4	1.5	0.9	2.0	1.0	0.6	0.4	1.4	0.7	0.4	0.3	1.2	0.6	0.4
Entitlements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Installed capacity															
Nuclear	1.4	1.4	-	-	0.85	0.85	-	-	0.76	0.76	-	-	0.45	0.45	-
Coal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Oil	1.0	0.6	0.4	-	-	-	-	-	0.28	0.28	-	-	0.84	0.82	-
Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hydropower	-	-	-	-	0.11	-	0.05	0.06	-	-	-	-	-	-	-
Pumped storage	-	-	-	-	0.16	-	-	0.16	-	-	-	-	-	-	-
Gas turbine	0.2	-	-	0.2	0.14	-	-	0.14	0.04	-	-	0.04	0.11	-	-
Total available capacity	2.6	2.0	0.4	0.2	1.26	0.85	0.05	0.36	1.08	1.04	-	0.04	1.40	1.27	-
Surplus/(deficit)†	(2.2)	(0.4)	(1.1)	(0.7)	(0.74)	(0.15)	(0.55)	(0.04)	(0.32)	0.34	(0.4)	(0.26)	0.20	0.67	(0.4)

*Installed capacity includes participation in Yankee Units.

†Figures in parentheses are projected deficits.

1

New England Gas Electric (Cambridge; New Bedford; Canal Electric)				Northeast Utilities (Holyoke Water Power)				New England Electricity System (Granite State; Massachusetts Electricity; Narragansett; New England Power Company)				Total of Foregoing Utilities				State Total
Total	Base	Int.	Peak	Total	Base	Int.	Peak	Total	Base	Int.	Peak	Total	Base	Int.	Peak	
1.10	0.90	0.07	0.13	0.17	0.15	0.01	0.01	4.24	2.26	1.13	0.85	10.32	6.59	2.10	1.63	10.0
0.7	0.4	0.2	0.1	0.1	0.05	0.03	0.02	5.6	2.8	1.8	1.0	12.4	6.25	3.93	2.22	13.7
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0.32	0.32	-	-	-	-	-	-	1.81	1.81	-	-	4.71	4.71	-	-	
-	-	-	-	-	-	-	-	1.64	1.12	0.52	-	1.76	1.12	0.64	-	
0.91	0.82	-	0.09	0.14	-	0.14	-	1.06	0.54	0.27	0.25	4.41	2.22	1.32	0.87	
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
-	-	-	-	0.03	0.02	0.01	-	0.48	-	0.47	0.01	0.62	0.02	0.53	0.07	
-	-	-	-	-	-	-	-	0.60	-	-	0.60	0.77	-	-	0.77	
0.11	-	-	0.11	-	-	-	-	0.04	-	-	0.04	0.53	-	-	0.53	
1.34	1.14	-	0.20	0.17	0.02	0.15	-	5.63	3.47	1.26	0.90	12.8	8.07	2.49	2.24	10.8
0.64	0.74	(0.2)	0.10	0.07	(0.03)	0.12	(0.02)	0.03	0.67	(0.54)	(0.10)	0.40	1.82	(1.44)	0.02	(2.9)
0.8	0.4	0.3	0.1	0.12	0.06	0.04	0.02	6.0	3.0	1.9	1.1	13.62	6.76	4.34	2.52	15.0
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0.41	0.41	-	-	-	-	-	-	2.87	2.87	-	-	6.10	6.10	-	-	
-	-	-	-	-	-	-	-	1.12	1.12	-	-	1.24	1.12	0.12	-	
0.87	0.82	-	0.05	0.14	-	0.14	-	0.89	0.54	0.27	0.08	3.89	2.24	1.22	0.43	
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
-	-	-	-	0.03	0.02	0.01	-	0.48	-	0.47	0.01	0.62	0.02	0.53	0.07	
-	-	-	-	-	-	-	-	0.60	-	-	0.60	0.76	-	-	0.76	
0.11	-	-	0.11	-	-	-	-	0.04	-	-	0.04	0.53	-	-	0.53	
1.39	1.23	-	0.16	0.17	0.02	0.15	-	6.00	4.53	0.74	0.73	13.14	9.48	1.87	1.79	11.5
0.59	0.83	(0.3)	0.06	0.05	(0.04)	0.11	(0.02)	-	1.53	(1.16)	(0.37)	(0.48)	2.72	(2.47)	(0.73)	(3.5)
1.2	0.6	0.4	0.2	0.16	0.08	0.05	0.03	7.7	3.8	2.4	1.5	17.26	8.58	5.35	3.33	19.9
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
0.45	0.45	-	-	-	-	-	-	3.02	3.02	-	-	6.48	6.48	-	-	
-	-	-	-	-	-	-	-	1.12	1.12	-	-	1.12	1.12	-	-	
0.84	0.82	-	0.02	0.14	-	0.14	-	0.62	0.54	-	0.08	2.88	2.24	0.54	0.10	
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
-	-	-	-	0.03	-	0.02	0.01	0.48	-	0.31	0.17	0.62	-	0.38	0.24	
-	-	-	-	-	-	-	-	0.60	-	-	0.60	0.76	-	-	0.76	
0.11	-	-	0.11	-	-	-	-	0.04	-	-	0.04	0.53	-	-	0.53	
1.40	1.27	-	0.13	0.17	-	0.16	0.01	5.88	4.68	0.31	0.89	12.39	9.84	0.92	1.63	11.4
0.20	0.67	(0.4)	(0.07)	0.01	(0.08)	0.11	(0.02)	(1.82)	0.88	(2.09)	(0.61)	(4.87)	1.26	(4.43)	(1.70)	(8.5)

Table 6-6

CAPACITY REQUIREMENTS FOR MAJOR UTILITIES IN MASSACHUSETTS (Thousands of Megawatts)

1

2

Table 6-7

CAPACITY REQUIREMENTS FOR MAJOR UTILITIES IN NEW HAMPSHIRE
(Thousands of Megawatts)

	PSC New Hampshire*				
	Total	Base	Int.	Peak	State Total
1977					
Installed capacity†	1.4	0.9	0.2	0.3	1.6
1986					
Required for load	2.3	1.2	0.7	0.4	2.4
Capacity					
Entitlements	-	-	-	-	-
Installed capacity					
Nuclear	0.56	0.56	-	-	
Coal	0.46	0.35	0.11	-	
Oil	0.63	0.43	-	0.20	
Gas	-	-	-	-	
Hydropower	0.06	-	0.06	-	
Pumped storage	-	-	-	-	
Gas turbine	0.10	-	-	0.10	
Total available capacity	1.81	1.34	0.17	0.30	3.9
Surplus/(deficit)‡	(0.49)	0.14	(0.53)	(0.10)	1.5
1989					
Required for load	2.5	1.2	0.8	0.5	2.6
Entitlements	-	-	-	-	-
Installed capacity					
Nuclear	0.56	0.56	-	-	
Coal	0.46	0.35	0.11	-	
Oil	0.47	0.41	-	0.06	
Gas	-	-	-	-	
Hydropower	0.06	-	0.06	-	
Pumped storage	-	-	-	-	
Gas turbine	0.10	-	-	0.10	
Total available capacity	1.65	1.32	0.17	0.16	3.7
Surplus/(deficit)‡	(0.85)	0.12	(0.63)	(0.34)	1.1
2001					
Required for load	3.2	1.6	1.0	0.6	3.4
Entitlements	-	-	-	-	-
Installed capacity					
Nuclear	0.56	0.56	-	-	
Coal	0.35	0.35	-	-	
Oil	0.43	0.43	-	-	
Gas	-	-	-	-	
Hydropower	0.06	-	0.06	-	
Pumped storage	-	-	-	-	
Gas turbine	0.10	-	-	0.10	
Total available capacity	1.50	1.34	0.06	0.10	3.7
Surplus/(deficit)‡	(1.70)	(0.26)	(0.94)	(0.50)	0.3

*3 MW internal combustion in Maine.

†Includes Yankee units.

‡Figures in parentheses indicate projected deficits.

Table 6-8

CAPACITY REQUIREMENTS FOR MAJOR UTILITIES IN VERMONT
(Thousands of Megawatts)

	Central Vermont PSC				Green Mountain Power Corp.				Total of the Foregoing Utilities				Vermont Total
	Total	Base	Int.	Peak	Total	Base	Int.	Peak	Total	Base	Int.	Peak	
1977													
Installed capacity*	0.30	0.25	0.01	0.04	0.22	0.14	0.01	0.07	0.52	0.39	0.02	0.11	0.75
1986													
Required for load	0.6	0.3	0.2	0.1	0.4	0.2	0.1	0.1	1.0	0.5	0.3	0.2	1.0
Capacity													
Entitlements (PASNY)	0.09	0.09	-	-	0.05	0.05	-	-	0.14	0.14	-	-	0.15
Installed capacity													
Nuclear	0.34	0.34	-	-	0.10	0.10	-	-	0.44	0.44	-	-	
Coal	-	-	-	-	-	-	-	-	-	-	-	-	
Oil	0.01	0.01	-	-	0.02	0.01	-	0.01	0.03	0.02	-	0.01	
Gas	-	-	-	-	-	-	-	-	-	-	-	-	
Hydropower	0.04	0.02	-	0.02	0.07	0.05	0.01	0.01	0.11	0.07	0.01	0.03	
Pumped storage	-	-	-	-	-	-	-	-	-	-	-	-	
Gas turbine	0.04	-	-	0.04	0.07	-	-	0.07	0.11	-	-	0.11	
Total available capacity	0.52	0.46	-	0.06	0.31	0.21	0.01	0.09	0.83	0.67	0.01	0.15	0.90
Surplus/(deficit)†	(0.08)	0.16	(0.2)	(0.04)	(0.09)	0.01	(0.09)	(0.01)	(0.17)	0.17	(0.29)	(0.05)	(0.10)
1989													
Required for load	0.6	0.3	0.2	0.1	0.4	0.2	0.1	0.1	1.0	0.5	0.3	0.2	1.0
Entitlements (PASNY)	0.09	0.09	-	-	0.05	0.05	-	-	0.14	0.14	-	-	0.15
Installed capacity													
Nuclear	0.34	0.34	-	-	0.10	0.10	-	-	0.44	0.44	-	-	
Coal	-	-	-	-	-	-	-	-	-	-	-	-	
Oil	0.01	0.01	-	-	0.02	0.01	-	0.01	0.03	0.02	-	0.01	
Gas	-	-	-	-	-	-	-	-	-	-	-	-	
Hydropower	0.04	-	0.02	0.02	0.07	0.04	0.02	0.01	0.11	0.04	0.04	0.03	
Pumped storage	-	-	-	-	-	-	-	-	-	-	-	-	
Gas turbine	0.04	-	-	0.04	0.07	-	-	0.07	0.11	-	-	0.11	
Total available capacity	0.52	0.44	0.02	0.06	0.31	0.20	0.02	0.09	0.83	0.64	0.04	0.15	0.87
Surplus/(deficit)†	(0.08)	0.14	(0.18)	(0.04)	(0.09	-	(0.08)	(0.01)	(0.17)	0.14	(0.26)	(0.05)	(0.13)
2001													
Required for load	0.9	0.4	0.3	0.2	0.6	0.3	0.2	0.1	1.5	0.7	0.5	0.3	1.5
Entitlements (PASNY)	0.09	0.09	-	-	0.05	0.05	-	-	0.14	0.14	-	-	0.15
Installed capacity													
Nuclear	0.34	0.34	-	-	0.10	0.10	-	-	0.44	0.44	-	-	
Coal	-	-	-	-	-	-	-	-	-	-	-	-	
Oil	0.01	0.01	-	-	0.02	0.01	-	0.01	0.03	0.02	-	0.01	
Gas	-	-	-	-	-	-	-	-	-	-	-	-	
Hydropower	0.04	-	0.01	0.03	0.07	0.04	-	0.03	0.11	0.04	0.01	0.06	
Pumped storage	-	-	-	-	-	-	-	-	-	-	-	-	
Gas turbine	0.04	-	-	0.04	0.07	-	-	0.07	0.11	-	-	0.11	
Total available capacity	0.52	0.44	0.01	0.07	0.31	0.20	-	0.11	0.83	0.64	0.01	0.18	0.87
Surplus/(deficit)†	(0.38)	0.04	(0.29)	(0.13)	(0.29)	(0.10)	(0.2)	0.01	(0.67)	(0.06)	(0.49)	(0.12)	(0.63)

*Excl..des entitlement from Power Authority of the State of New York (PASNY); includes Yankee units.

†Figures in parentheses indicate deficits.

Table 6-9

CAPACITY REQUIREMENTS FOR MAJOR UTILITIES IN RHODE ISLAND
(Thousands of Megawatts)

	Total	Base	Intermediate	Peak
1977				
Installed capacity	0.3			
1986				
Required for load	1.8	0.9	0.6	0.3
Total available capacity	1.3			
Surplus/(deficit)*	(0.5)			
1989				
Required for load	1.9	0.9	0.6	0.4
Total available capacity	2.5			
Surplus/(deficit)*	0.6			
2001				
Required for load	1.9	0.9	0.6	0.4
Total available capacity	2.5			
Surplus/(deficit)*	0.6			

*Figures in parentheses indicate a projected deficit.

These data should help windpower advocates to identify the best utility "customers" for their energy.

PSNH, CMPC, and NEES

SRI selected these three utilites for additional analyses because the Shipyard currently buys electricity from PSNH and might buy it from CMPC at some future time, and because NEES will buy electricity from windpower or other alternative sources at prices equivalent to the value of the fuel that is saved.

Again, SRI's analysis is based on announced construction plans for new units and facilities. SRI made its own estimates of the division of units into base-load, intermediate-load, and peak-load service; used about 35 years as the retirement age for fossil-fired units; and used its own projections for fuel price increases and load growth for each of the utilities. Comparisons of these estimates with the projections of capacity and demand made by others should be avoided unless potential differences in the significant assumptions are known and understood.

The capacity of expected retirements and additions of generating units for all three utilities is summarized in Table 6-10, and the individual units are also identified. It can be seen that the 552 MW of capacity of the anticipated oil-fired retirements will be replaced mainly by additions of 459 MW of coal-fired units and 95 MW of hydropower. All significant capacity growth in the generating mix of these utilities will come from nuclear power. Further delays or cancellations of any of the proposed nuclear units, such as Seabrook or Nepco, will leave these utilities with three possible options for making up potential deficits

Table 6-10

INSTALLED CAPACITY AND PROPOSED ADDITIONS AND RETIREMENTS*
FOR SELECTED NEW ENGLAND UTILITIES
(Megawatts)

	Oil	Hydro Pumped Storage	Nuclear	Coal	Gas Turbine	Internal Com-bustion	Total
1978 Capacity							
Public Service Company of New Hampshire (PSNH)	644	56	101	460	95	3	1,359
New England Electric System (NEES)	1,106	1,115	401	1,600	40	76	4,338
Central Maine Power Company (CMPC)	757	269	381	--	39	4	1,450
Total installed capacity, 1978	2,507	1,440	883	2,060	174	83	7,147
Proposed Additions† and Retirements‡							Capacity--Cumulative Total
1979	(68)						7,079
1980	(20)						7,059
1981		12					7,071
1982	(69)						7,002
1983			403				7,405
1984	(66)						7,339
1985			567				7,906
1986	(82)		1,076	459			9,359
1987	(115)						9,244
1988	(49)	83	1,094				10,372
1989	(83)						10,289
Total installed capacity, 1989	1,955	1,535	4,023	2,519	174	83	

*( ) = Retirement

Table 6-10 (Concluded)

†Additions are listed below. Except for hydroelectric units, all additions are jointly owned.

Hydro	Capacity (MW)	Name	Location	Owners
1981	12	Brunswick/Topsham	Cumberland County, ME	CMPC
1988	83	Cold Stream	Location unknown	CMPC
	95			
Nuclear				**Participation (MW)**
1983	403	Seabrook I	Seabrook, NH	PSNH--230 NEES--115 CMPC-- 58
1985	403	Seabrook 2	Seabrook, NH	PSNH--230 NEES--115 CMPC-- 58
	164	Pilgrim 2	Plymouth, MA	NEES--130 CMPC-- 34
1986	909	NEPCO I	Possible site at Charlestown, RI	NEES--909
	167	Millstone 3	New London, CT	NEES--138 CMPC-- 29
1988	909	NEPCO 2	Possible site at Charlestown, RI	NEES--909
	185	Montague I	Montague Plain, MA	NEES--150 CMPC-- 35
	3,140			
Coal				
1986	459	Sears Island	Waldo County, ME	CMPC

‡The retirements are oil-fired units, as follows:

1979	20	Mason I	Lincoln County, ME	CMPC
	8	Daniel 3-5	Rockingham County, NH	PSNH
	40	Manchester 9	Providence, RI	NEES
1980	20	Manchester I	Hillsborough County, NH	PSNH
1982	46	Manchester 10	Providence, RI	NEES
	23	Cape	Cumberland County, ME	CMPC
1984	46	Manchester 11	Providence, RI	NEES
	20	Mason 2	Lincoln County, ME	CMPC
1986	82	Salem I	Salem Harbor, ME	NEES
1987	82	Salem 2	Salem Harbor, ME	NEES
	33	Mason 3	Lincoln County, ME	CMPC
1988	14	Daniel 6-7	Rockingham County, NH	PSNH
	35	Mason 4	Lincoln County, ME	CMPC
1989	50	Schiller 5	Rockingham County, NH	PSNH
	33	Mason 5	Lincoln County, ME	CMPC
	552			

between now and 1989. New coal-fired units are encountering permit and construction delays equivalent to those faced by nuclear units, so it is too late to plan coal units for service by 1989. The utilities can choose to continue using the oil-fired capacity beyond its usual retirement age, thereby incurring the penalties of continuing oil consumption, lower unit reliability, and higher operating and maintenance costs. They can purchase more electricity from Canada, until the Canadian government changes its policy on export of electricity or until Canadian capacity is used up. A third option is the last-minute purchase and installation of more combustion turbines--such units can be in place within about 2 years after decisions are made. The relative inefficiency of these units, compared with steam turbines, translates to a 34% increase in the amount of oil or gas burned per kilowatt-hour. For intermediate service, this increase amounts to 2.4 to 3.2¢/kWh for the fuel at present prices.

If capacity deficits occur through delays or cancellations of the nuclear units, the reliability of service to the Navy will suffer along with that of service to all other industrial customers. It is not logical to expect that the Navy will receive special consideration in peacetime. Nor is it logical to expect any Navy-owned WEGS at the Mt. Washington site to generate electricity that can somehow be differentiated after it is fed into the NEPOOL grid for wheeling to the Shipyard. The Navy's purchase and installation of the new 7,500-kW unit was wise insofar as it reduced or eliminated Navy dependence on electricity purchases.

The laws of New Hampshire and Maine, and perhaps other New England states, exempt windpower and other alternative energy producers from state utility regulations and reporting requirements if those producers

are small (less than 5 MW capacity in New Hampshire) or if they are companies whose primary business is something other than the generation of electricity. These laws also require that the franchise utility purchase surplus electricity from such producers. Generally, the price being found suitable by state public utilities commissions is equivalent to at least the cost of the fuel that is saved by the utility, or about 4¢/kWh. Federal laws require that utilities wheel or transmit power from alternative energy producers if these producers arrange sale of their electricity to remote customers. SRI presents the sales by sector for PSNH, CMPC, and NEES in Tables 6-11 through 6-13 to supply guidance on the windpower applications that may be fostered by these laws.

Industrial customers of these utilities may purchase some increase in the reliability of their individual supply by installing WEGS, just as the Shipyard is increasing its supply reliability by the installation of the new turbine. Such industrial customers could rely on the windpower for their own needs and are assured of a market for any surplus electricity generated at night or during their other periods of low use.

The resale sector sales listed for the utilities are largely made to small municipal utilities and cooperatives. These utility customers could enhance their individual reliability with WEGS installations. They could also generate their electricity at lower cost because of their likely lower fixed charge rates for capitalization of the WEGS. In Section 4, "Institutional Considerations," fixed charge rates are estimated at 7.48% for municipally owned projects and 6.28% for Rural Electric Administration (REA) cooperatives, instead of the 17.21% needed by investor-owned utilities. These lower fixed charge rates would result in electricity

Table 6-11

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
ELECTRIC POWER SALES BY SECTOR
(Millions of Kilowatt-Hours)

	Sales						Proportion to Each Sector (Percent)					
Year	Residential	Commercial	Industrial	Other	Resale	Total	Residential	Commercial	Industrial	Other	Resale	Total
1971	1,214	424	1,430	55	1,180	4,303	28.2	9.9	33.2	1.3	27.4	100.0
1972	1,394	479	1,552	51	1,398	4,874	28.6	9.8	31.9	1.0	28.7	100.0
1973	1,512	513	1,693	57	1,360	5,133	29.5	10.0	33.0	1.1	26.5	100.0
1974	1,555	502	1,655	52	1,290	5,054	30.8	9.9	32.8	1.0	25.5	100.0
1975	1,556	518	1,596	50	1,336	5,056	30.8	10.2	31.6	1.0	26.4	100.0
1976	1,680	542	1,764	44	1,257	5,287	31.8	10.3	33.4	0.8	23.8	100.0
1977	1,713	570	1,808	50	1,445	5,586	30.7	10.2	32.4	0.9	25.8	100.0
1978	1,768	608	1,995	63	1,329	5,753	30.7	10.5	34.6	1.1	23.1	100.0
1986	2,300	800	2,700	80	1,700	7,600	30.2	10.9	35.0	1.1	22.8	100.0
1989	2,500	900	2,900	90	1,900	8,300	29.7	11.1	35.5	1.1	22.6	100.0
Increase, 1971-78 (%)	5.1	5.3	4.9	2.0	1.7	4.2						

Table 6-12

CENTRAL MAINE POWER COMPANY
SALES BY SECTOR
(Millions of Kilowatt-Hours)

		Amount					Proportion to Each Sector (Percent)				
Year	Total	Residential	Commercial	Industrial	Other	Resale	Residential	Commercial	Industrial	Other	Resale
1971	4,059.4	1,405.9	796.9	1,486.9	71.2	298.5	34.6	19.6	36.6	1.89	7.4
1972	4,554.5	1,593.4	895.6	1,611.5	78.9	375.0					
1973	5,265.4	1,700.3	969.2	1,653.3	81.5	861.1	32.3	18.4	31.4	1.5	16.4
1974	5,275.7	1,819.9	969.0	1,751.1	78.8	656.9					
1975	4,809.4	1,915.6	1,024.6	1,707.9	82.1	79.3					
1976	5,221.6	2,143.9	1,182.8	1,758.7	48.9	87.4	41.1	22.7	33.7	0.9	1.6
1977	5,572.5	2,213.8	1,215.2	2,018.2	50.1	75.2					
1978	5,877.8	2,319.6	1,251.5	2,145.6	50.6	110.5	39.5	21.3	36.5	0.9	1.8
1986	7,272	3,011	1,556	2,654	51.0	--	41.4	21.4	35.6	0.7	
1989	7,877	3,261	1,686	2,875	55.0	--	41.4	21.4	35.6	0.7	
Increase or decrease,* 1971-1978 (%)	5.4	7.5	6.7	5.4	5.0	15.2					

*Figures in parentheses denote decreases.

Table 6-13

NEW ENGLAND ELECTRIC SYSTEM
ELECTRIC POWER SALES BY SECTOR
(Billions of Kilowatt-Hours)

Year	Sales						Proportion to Each Sector (Percent)					
	Residential	Commercial	Industrial	Other	Resale	Total	Residential	Commercial	Industrial	Other	Resale	Total
1971	4.7	3.5	3.3	0.2	1.7	13.4	35.1	26.1	24.6	1.5	12.7	100.0
1972	5.1	3.9	3.6	0.2	1.5	14.3	35.7	27.3	25.2	1.4	10.4	100.0
1973	5.4	4.3	3.9	0.2	1.6	15.4	35.1	27.9	25.3	1.3	10.4	100.0
1974	5.3	4.1	3.7	0.2	1.7	15.0	35.4	27.3	24.7	1.3	11.3	100.0
1975	5.5	4.2	3.4	0.2	2.0	15.3	35.9	27.5	22.2	1.3	13.1	100.0
1976	6.0	4.5	3.7	0.2	1.8	16.2	37.1	27.8	22.8	1.2	11.1	100.0
1977	5.7	4.6	3.7	0.2	1.6	15.8	36.1	29.1	23.4	1.3	10.1	100.0
1986	7.6	6.1	4.9	0.2	2.3	21.1	36.0	29.0	23.0	1.0	11.0	100.0
1989	8.2	6.7	5.3	0.2	2.5	22.9	36.0	29.0	23.0	1.0	11.0	100.0
Increase, 1971-1977 (%)	3.3	4.7	2.0		0	2.8						

costs of about 1.6 or 1.4¢/kWh, instead of the 3.4¢/kWh estimated for a Boeing Mod 2 with utility financing. Windpower proponents, then, would be encouraged to look to the industrial and resale sectors for the likely nonutility customers.

When WEGS are considered as fuel savers, the fuel prices paid by the utilities becomes an important economic index for determining the feasibility of using windpower. General guidance on fuel prices was given in the earlier section on economic considerations. SRI determined the prices paid by PSNH, CMPC, and NEES for the primary fuels in 1978 and early 1979 and projected price increases to 1989. These data are summarized for the three utilities of special interest in Table 6-14. Because the data are presented in constant 1979 dollars, it will be necessary to adjust the prices by appropriate inflation indexes in the future.

To project capacity required by a utility, SRI begins with a projection of megawatt-hours of demand. Purchased electricity is subtracted to determine the amount to be generated. The estimated annual load factor of the generating units is used to calculate the capacity that will be required to supply that demand. Allowance is then made for capacity reserve and additions and retirements of generating units. Because these projections are based on SRI's own projections of load growth and estimates of retirement dates for some of the generating units, our capacity requirements and deficits estimates will differ from those of other sources. Tables 6-15 through 6-17 summarize SRI's estimated loads and capacity requirements for PSNH, CMPC, and NEES.

Table 6-14

FUEL COST PROJECTIONS
(Dollars per Million Btu)

	Nuclear*	Coal†		Residual Oil†			Distillate†		
		PSNH	CMPC	PSNH	CMPC	NEES	PSNH	CMPC	NEES
1979	0.64	1.503	--	2.027	2.201	2.071	3.058	3.380	3.348
1980	0.64	1.505	--	2.068	2.245	2.112	3.119	3.448	3.415
1981	0.64	1.518	--	2.190	2.290	2.155	3.182	3.517	3.483
1982	0.64	1.526	--	2.157	2.345	2.198	3.245	3.587	3.553
1983	0.64	1.533	--	2.194	2.392	2.242	3.310	3.659	3.624
1984	0.64	1.541	--	2.238	2.440	2.229	3.376	3.732	3.697
1985	0.64	1.549	--	2.283	2.488	2.332	3.444	3.807	3.771
1986	0.67	1.556	1.608	2.329	2.538	2.379	3.513	3.883	3.846
1987	0.70	1.564	1.624	2.375	2.589	2.426	3.583	3.960	3.923
1988	0.73	1.572	1.640	2.423	2.640	2.475	3.655	4.039	4.001
1989	0.76	1.580	1.656	2.471	2.693	2.524	3.728	4.120	4.081

Sources: *Department of Energy projection, Nuclear Engineering International (August 1978).

†Prices paid in 1978-1979 and SRI's projection of future prices.

Table 6-15

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE: CAPACITY REQUIRED FOR LOAD

Year	LOAD REQUIREMENTS ($MWX10^3$)						GENERATION ($kWhX10^9$)								CAPACITY ($MWX10^3$)								Surplus or Deficit ($MWX10^3$)§
							Projected Generation *†				Projected Requirements†				Installed Capacity†				Required Capacity				
	Generation plus 7.2% Line Losses ($kWh X10^9$)	Avg.	Peak (60% LF)	Required Peak +20% Margin	Planned Capacity after Retirements	Margin Held‡ (%)	Total	Base	Int.	Peak	Total	Base (70%)	Int. (25%)	Peak (5%)	Total	Base	Int.	Peak	Total	Base	Int.	Peak	
1979	6.5	0.74	1.24	1.50	1.34	8.1	4.8	4.2	0.5	0.1	6.5	4.6	1.6	0.3	1.35	0.99	0.16	0.20	1.99	0.98	0.62	0.39	(0.64)
1980	6.8	0.78	1.29	1.55	1.33	3.1	4.6	3.8	0.7	0.1	6.8	4.8	1.7	0.3	1.33	0.87	0.27	0.19	2.06	1.02	0.64	0.40	(0.73)
1981	7.0	0.80	1.33	1.60	1.33	-	4.4	3.6	0.7	0.1	7.0	4.9	1.8	0.3	1.33	0.87	0.27	0.19	2.12	1.05	0.66	0.41	(0.79)
1982	7.2	0.82	1.37	1.64	1.33	-	4.4	3.6	0.7	0.1	7.2	5.0	1.8	0.4	1.33	0.87	0.27	0.19	2.19	1.09	0.68	0.42	(0.86)
1983	7.4	0.84	1.41	1.69	1.56	10.6	4.7	3.9	0.7	0.1	7.4	5.2	1.8	0.4	1.56	1.10	0.27	0.19	2.25	1.12	0.70	0.43	(0.69)
1984	7.6	0.87	1.45	1.74	1.56	7.6	5.0	4.2	0.7	0.1	7.6	5.3	1.9	0.4	1.56	1.10	0.27	0.19	2.31	1.15	0.72	0.44	(0.75)
1985	7.8	0.89	1.48	1.78	1.79	20.9	5.5	4.7	0.7	0.1	7.8	5.5	1.9	0.4	1.79	1.33	0.27	0.19	2.38	1.18	0.74	0.46	(0.59)
1986	8.1	0.92	1.54	1.85	1.79	16.2	5.8	5.1	0.6	0.1	8.1	5.7	2.0	0.4	1.79	1.33	0.27	0.19	2.47	1.22	0.77	0.48	(0.68)
1987	8.4	0.96	1.60	1.92	1.79	11.9	6.0	5.4	0.5	0.1	8.4	5.9	2.1	0.4	1.79	1.33	0.27	0.19	2.56	1.27	0.80	0.49	(0.77)
1988	8.6	0.98	1.63	1.96	1.79	9.8	6.0	5.4	0.5	0.1	8.6	6.0	2.2	0.4	1.77	1.33	0.27	0.17	2.62	1.30	0.82	0.50	(0.85)
1989	8.9	1.02	1.69	2.03	1.72	1.8	5.9	5.4	0.4	0.1	8.9	6.2	2.2	0.5	1.72	1.33	0.27	0.17	2.72	1.34	0.85	0.53	(1.00)

*Estimate based on unit-by-unit calculation.

†Includes joint ownership units.

‡Based on current announcements.

§Difference between installed capacity and required capacity; figures in parentheses are deficits.

Year	Load Requirements (MW)*						Generation (kWhX10^6)					
							Projected Generation*†				Projec Requirem	
	Generation plus 8.1% line losses (kWhX10^6)	Avg. Load	Peak Load (60% LF)	Required Peak +20% Margin	Planned Capacity After Retirements	Margin Held* (%)	Total	Base	Int.	Peak	Total	Base (70%)
1978					1,450							
1979	6,482	740	1,233	1,480	1,430	16.0	6,638	5,166	1,252	220	6,482	4,537
1980	6,582	751	1,252	1,503	1,430	14.2	6,610	5,142	1,238	230	6,582	4,607
1981	6,780	774	1,290	1,547	1,442	11.8	6,655	5,200	1,214	241	6,780	4,746
1982	6,983	797	1,329	1,594	1,419	6.8	6,520	5,106	1,195	219	6,983	4,888
1983	7,193	821	1,369	1,642	1,477	7.9	6,589	5,157	1,168	234	7,193	5,035
1984	7,409	846	1,410	1,692	1,457	3.3	6,554	5,222	1,058	274	7,409	5,186
1985	7,631	871	1,452	1,742	1,549	6.7	6,086	5,034	753	299	7,631	5,342
1986	7,861	897	1,496	1,795	2,037	36.2	8,299	7,259	720	320	7,861	5,503
1987	8,073	922	1,536	1,843	2,004	30.5	9,094	8,107	717	270	8,073	5,651
1988	8,291	946	1,577	1,893	2,087	32.3	9,697	8,771	706	220	8,291	5,804
1989	8,515	972	1,620	1,944	2,054	26.8	10,015	9,100	694	220	8,515	5,961

*Based on current announcements.

†Based on unit-by-unit calculations.

‡Includes joint ownership units.

§Difference between installed and required capacity; figures in parentheses denote deficits.

1

x10⁶)				Capacity (MW)								Surplus or Deficit§ (MW)
	Projected Requirements‡			Installed Capacity*†‡				Required Capacity				
tal	Base (70%)	Int. (25%)	Peak (5%)	Total	Base	Int.	Peak	Total	Base	Int.	Peak	
				1,450	915	330	205					
482	4,537	1,621	324	1,430	915	330	185	1,371	680	428	263	59
582	4,607	1,646	329	1,430	911	330	189	1,392	691	434	267	38
780	4,746	1,695	339	1,442	916	330	196	1,435	712	447	276	7
983	4,888	1,746	349	1,419	916	330	173	1,478	733	461	284	(59)
193	5,035	1,798	360	1,477	968	328	181	1,523	755	475	293	(46)
409	5,186	1,852	370	1,457	968	302	187	1,568	778	489	301	(111)
631	5,342	1,908	382	1,549	1,060	210	279	1,616	801	504	311	(67)
861	5,503	1,965	393	2,037	1,546	205	286	1,664	825	519	320	373
073	5,651	2,018	404	2,004	1,534	217	253	1,677	832	523	322	327
191	5,804	2,073	415	2,087	1,652	217	218	1,722	854	537	331	365
315	5,961	2,129	426	2,054	1,652	217	185	1,770	878	552	340	284

Table 6-16

CENTRAL MAINE POWER COMPANY: PROJECTED CAPACITY REQUIRED FOR LOAD

1 2

Year	LOAD REQUIREMENTS (MWX10³)								GENERATION* (kWhX10⁹)					
									Projected Generation*†				Proje[cted] Require[ments]	
	Generation (kWh X10⁹)	Generation plus 7.5% Line Losses (kWh X10⁹)	Total Generation Required‡ (kWh X10⁹)	Avg.	Peak (60% LF)	Required Peak Plus 20% Margin	Planned Capacity after Retirements	Margin Held§ (%)	Total	Base	Int.	Peak	Total	Base (70%)
1978	16.1	17.3	17.4	1.98	3.0	3.6	4.3	44.6	17.24	12.64	4.22	0.38	17.4	12.1
1979	16.6	17.8	17.9	2.04	3.4	4.08	4.3	26.4	16.96	11.95	4.45	0.56	17.9	12.5
1980	17.2	18.5	18.6	2.12	3.53	4.24	4.3	21.8	16.70	11.52	4.49	0.74	18.6	13.0
1981	17.8	19.1	19.2	2.19	3.65	4.38	4.3	17.8	16.46	11.37	4.38	0.71	19.2	13.4
1982	18.4	19.8	19.9	2.27	3.78	4.54	4.3	12.5	16.18	11.18	4.33	0.67	19.9	13.9
1983	19.0	20.4	20.5	2.34	3.90	4.68	4.4	12.0	16.12	11.18	4.27	0.67	20.5	14.3
1984	19.6	21.1	21.2	2.42	4.03	4.84	4.3	7.2	16.05	11.23	4.18	0.64	21.2	14.8
1985	20.3	21.8	21.9	2.50	4.17	5.00	4.6	9.5	16.33	11.59	4.12	0.62	21.9	15.3
1986	21.1	22.7	22.8	2.60	4.33	5.20	5.5	27.7	18.20	13.48	4.27	0.45	22.8	15.9
1987	21.7	23.3	23.4	2.67	4.45	5.34	5.4	22.4	19.87	15.41	4.17	0.29	23.8	16.6
1988	22.3	24.0	24.1	2.75	4.58	5.50	6.5	42.0	22.47	18.09	4.09	0.29	24.1	16.8
1989	22.9	24.6	24.7	2.82	4.70	5.64	6.5	38.5	24.62	20.31	4.02	0.29	24.7	17.2

*Includes joint ownership units.

†Based on unit-by-unit calculations.

‡Includes 0.32×10^{12} kWh pump storage less 0.23×10^{12} kWh energy derived from pump storage.

§Based on announcements.

■Difference between installed capacity and required capacity; figures in parentheses represent deficits.

*				CAPACITY (MW)								Surplus or Deficit■ (MW)
	Projected Requirements*			Installed*†				Required				
tal	Base (70%)	Int. (25%)	Peak (5%)	Total	Base	Int.	Peak	Total	Base	Int.	Peak	
7.4	12.18	4.35	0.87	4,338	2,338	1,147	853	4,321	2,143	1,348	830	17
7.9	12.53	4.48	0.89	4,298	2,182	1,221	895	4,442	2,205	1,388	849	(300)
8.6	13.02	4.65	0.93	4,298	2,115	1,206	977	4,619	2,291	1,441	887	(466)
9.2	13.44	4.80	0.96	4,298	2,115	1,206	977	4,768	2,365	1,487	916	(615)
9.9	13.93	4.98	0.99	4,252	2,110	1,217	931	4,940	2,452	1,543	945	(833)
0.5	14.35	5.13	1.02	4,367	2,215	1,221	931	5,088	2,526	1,589	973	(866)
1.2	14.84	5.30	1.06	4,321	2,215	1,221	885	5,265	2,612	1,642	1,011	(1,089)
1.9	15.33	5.48	1.09	4,566	2,460	1,221	885	5,436	2,698	1,698	1,040	(1,130)
2.8	15.96	5.70	1.14	5,531	3,462	1,259	810	5,663	2,809	1,766	1,088	132
3.8	16.66	5.95	1.19	5,449	3,462	1,259	728	5,786	2,870	1,804	1,112	337
4.1	16.87	6.03	1.20	6,508	4,521	1,259	728	5,855	2,906	1,828	1,121	653
4.7	17.29	6.18	1.23	6,508	4,521	1,259	728	6,002	2,978	1,874	1,150	506

deficits.

Table 6-17

NEW ENGLAND ELECTRIC SYSTEM:
CAPACITY REQUIRED FOR LOAD

1

2

Tables 6-18 through 6-20 provide descriptions of the generating mix for the three utilities; the historical capacity factors for each unit; and SRI projections of the annual average dispatch of those units that will be needed to generate the required electricity. The tables are meant to convey the complexity of the generating mixes actually used to supply electricity and the fluidity of the electricity generating business. For example, PSNH has hydropower units with capacity factors greater than 70% that have been regularly used in intermediate service. CMPC has Hydro, 12 MW, now in base-load service but likely to be used for intermediate service starting in 1987. Hydro 6 can be expected to shift from intermediate service to peak service in 1983. Any decisions regarding windpower utilization must therefore be made in the context of the most recent utility or NEPOOL efforts. Published data such as these tables can only supply general direction and assistance.

Tables 6-21 through 6-23 restate the SRI estimates of energy that will be generated by PSNH, CMPS, and NEES alongside of SRI's estimate of the mix of fuels that will be used for this generation. Oil is the fuel most likely to be displaced or supplanted by windpower, so windpower advocates can use these tables in the preparation of fuel savings estimates.

Portsmouth Naval Shipyard

The Portsmouth Naval Shipyard is located about 50 mi (80 km) north of Boston, Massachusetts, at the southernmost tip of Maine. The Shipyard is on an island in Kittery, Maine, across from Portsmouth, New Hampshire, near the mouth of the Piscataqua River.

	Base															
	Merrimack I	Merrimack 2	Newington I (cycling unit)	Seabrook I (J) 20%	Seabrook 2 (J) 20%	Wyman #4 (J)3.1433%	Yankee Atomic (Rowe)(J)7%	Conn. Yankee (Haddam Neck) (J)5%	Maine Yankee (J) 7%	Vermont Yankee (J) 7%	Pilgrim #2 (J) Sell	Millstone #3 (J) Sell	Total for Base Load Equipment	Schiller 5	Schiller 6	Amoskeag 1-3
Startup date	1960	1968	1974	1983	1985	1978	1961*	1968*	1972*	1972*	1984†	1982†		1955	1957	1922-1924
Fuel	Coal	Coal	Oil	Nuc.	Nuc.	Oil	Nuc.	Nuc.	Nuc.	Nuc.	Nuc.	Nuc.		Oil‡	Oil‡	Hydro
Rating (MW)	114.0	346.0	414.0	230.0	230.0	11.44§	12.25§	28.75§	38.45§	21.12§	0	0		50.0	50.0	16.0
Operator				PSNH	PSNH	CM	YA	CY	MY	VN	BE	CLP				
Capacity factor(%)														(4 units)		
1976	48.5		32.7											50.0		66.0
1977	62.0		37.3											28.0		61.4
1978	48.5		44.3			3.1	67.4■	80.1■	74.4■	78.4■				11.2		52.9
Generation																
1979	0.4	1.5	1.6	--	--	0.05	0.07	0.20	0.24	0.14	--	--	4.20	0.08	0.08	0.08
1980	Int.	1.5	1.6	--	--	0.05	0.07	0.20	0.24	0.14	--	--	3.80	0.07	0.07	0.08
1981	--	1.4	1.5	--	--	0.05	0.07	0.20	0.24	0.14	--	--	3.60	0.07	0.07	0.08
1982	--	1.4	1.5	--	--	0.05	0.07	0.19	0.23	0.14	--	--	3.58	0.06	0.06	0.08
1983	--	1.4	1.4	0.4	--	0.05	0.06	0.19	0.23	0.14	--	--	3.87	0.06	0.06	0.08
1984	--	1.4	1.4	0.8	--	0.05	0.06	0.19	0.23	0.13	--	--	4.26	0.06	0.06	0.08
1985	--	1.3	1.4	1.0	0.4	0.04	0.06	0.18	0.22	0.13	--	--	4.73	0.05	0.05	0.08
1986	--	1.3	1.3	1.1	0.8	0.04	0.06	0.18	0.22	0.13	--	--	5.13	0.05	0.05	0.07
1987	--	1.3	1.3	1.2	1.0	0.04	0.06	0.18	0.22	0.13	--	--	5.43	0.04	0.04	0.07
1988	--	1.2	1.3	1.2	1.1	0.04	0.06	0.18	0.22	0.13	--	--	5.43	0.04	0.04	0.07
1989	--	1.2	1.2	1.2	1.2	0.04	0.06	0.17	0.21	0.12	--	--	5.40	Retire	0.03	0.07

Key:
- GT = gas turbine
- IC = internal combustion
- PSNH = Public Service of New Hampshire
- CM = Central Maine
- YA = Yankee Atomic
- CY = Connecticut Yankee
- MY = Maine Yankee
- VN = Vermont Nuclear
- BE = Boston Edison
- CLP = Connecticut Light and Power

*Company treats Yankee Units as purchased power.

†Interest in Pilgrim (1.180 MW in 1984) and Millstone #3 (1,156 MW in 1982) to be sold.

‡According to the U.S. Environmental Protection Agency, these units will burn coal by 1981.

§Company

■Cumulati

	Intermediate																		
	Ayers Island 1-3	Canaan (Vt.) (J)	Eastmann Falls I	Eastman Falls 2	Garvins 3-4	Gorham 1-2	Gorham 3-4	Hookset I	Jackman I	Smith	Schiller 3	Schiller 4	Merrimack I (from Base)	Total for Intermediate Load Equipment	Lost Nation GT 1	Schiller GT 1	White Lake GT 1	Swans Falls (Maine)	
2- 4	1924	1938	1937	1912	1925	1917	1923	1927	1925	1948	1949	1952	1960		1969	1970	1968	1948	19 19
ro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Oil	Oil	Coal		GT	GT	GT	IC	Oi
.0	8.4	1.1	3.0	3.0	5.6	1.1	1.1	1.6	3.2	15.0	29.0	50.0	114.0		18.0	21.3	18.6	3.0	
.0	65.5	86.5	73.0		41.1	81.9		82.1	40	77.6					0.4	1.1	2.1	1.5	
.4	60.8	85.4	67.3		46.9	83.0		66.4	41.4	88.5					0.3	0.4	0.5	0.4	
.9	51.6	83.3	57.0		48.9	77.1		50.7	32.9	77.9					--	0.3	0.6	0.8	
.08	0.04	0.01	0.01		0.02	0.01		0.01	0.01	0.1	Peak	Peak	Base	0.45	0.001	0.001	0.001	--	Re
.08	0.04	0.01	0.01		0.02	0.01		0.01	0.01	0.1	--	--	0.3	0.73	0.001	0.001	0.001	--	
.08	0.04	0.01	0.01		0.02	0.01		0.01	0.01	0.1	--	--	0.3	0.73	0.001	0.001	0.001	--	
.08	0.04	0.01	0.01		0.02	0.01		0.01	0.01	0.1	--	--	0.3	0.71	0.001	0.001	0.001	--	
.08	0.04	0.01	0.01		0.02	0.01		0.01	0.01	0.1	--	--	0.3	0.71	0.001	0.001	0.001	--	
.08	0.04	0.01	0.01		0.02	0.01		0.01	0.01	0.1	--	--	0.3	0.71	0.001	0.001	0.001	--	
.08	0.04	0.01	0.01		0.02	0.01		0.01	0.01	0.1	--	--	0.3	0.69	0.001	0.001	0.001	--	
.07	0.03	0.01	0.01		0.02	0.01		0.01	0.01	0.1	--	--	0.24	0.61	0.001	0.001	0.001	--	
.07	0.03	0.01	0.01		0.02	0.01		0.01	0.01	0.09	--	--	0.2	0.54	0.001	0.001	0.001	--	
.07	0.03	0.01	0.01		0.02	0.01		0.01	0.01	0.09	--	--	0.2	0.54	0.001	0.001	0.001	--	
.07	0.03	0.01	0.01		0.02	0.01		0.01	0.01	0.09	--	--	0.2	0.49	0.001	0.001	0.001	--	

any share of jointly owned equipment. Full capacity of units is as follows:

	Megawatts		Megawatts
Seabrook I	1,150	Connecticut Yankee	575
Seabrook 2	1,150	Maine Yankee	769
Wyman #4	355	Vermont Yankee	528
Yankee Atomic	175		

lative capacity factor from Nuclear Engineering International (April 1978).

1 2

Peak											
Schiller GT 1	White Lake GT 1	Swans Falls (Maine)	Daniel 3-5	Daniel 6-7	Manchester I	Merrimack GT3	Merrimack GT4	Schiller 3	Schiller 4	Total for Peak Load Equipment	Total System Generation
1970	1968	1948	1918-1923	1937-1944	1938	1968	1969	1949	1952		
GT	GT	IC	Oil	Oil	Oil	GT	GT	Oil	Oil		
1.3	18.6	3.0	8.0	14.0	20.0	18.0	19.0	29.0	50.0		
1.1	2.1	1.5	2.2		3.4	0.7		From	From		
0.4	0.5	0.4	0.7		0.4			Int.	Int.		
0.3	0.6	0.8	5.4		0.2	0.2					
0.001	0.001	--	Retire	0.001	0.002	0.001		0.1		0.107	4.757
0.001	0.001	--	--	0.001	Retire	0.001		0.1		0.105	4.635
0.001	0.001	--	--	0.001	--	0.001		0.09		0.095	4.425
0.001	0.001	--	--	0.001	--	0.001		0.09		0.095	4.385
0.001	0.001	--	--	0.001	--	0.001		0.08		0.085	4.665
0.001	0.001	--	--	0.001	--	0.001		0.07		0.075	5.045
0.001	0.001	--	--	0.001	--	0.001		0.06		0.065	5.485
0.001	0.001	--	--	0.001	--	0.001		0.05		0.055	5.795
0.001	0.001	--	--	0.001	--	0.001		0.05		0.055	6.025
0.001	0.001	--	--	Retire	--	0.001		0.05		0.054	6.024
0.001	0.001	--	--	--	--	0.001		0.04		0.044	5.934

Table 6-18

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
GENERATION BY UNIT
(Billions of Kilowatt-hours)

1 3

	Androscoggin 3	Bonny Eagle 1-6	Cataract I	Deer Rips 1-7	Fort Halifax	Gulf Island	Hiram I
Startup date	1928	1910	1937	1903-1924	1908	1926	1917
Fuel	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydr
Rating (MW)	4	7	6	6	2	18	2
Operator							
Capacity factor (%)							
1977	90.5	73.5	66.9	65.6	61.1	83.9	100.
1978	82.9	63.9	54.5	58.3	37.4	75.3	85.
Generation ($kWh \times 10^9$)							
1979	29.8	42.9	34.2	34.2	8.6	134.0	14.
1980	29.4	42.3	33.6	33.6	Peak	132.4	14.
1981	29.1	Intermed.	33.1	33.1	--	130.9	14.
1982	28.7	--	32.6	32.6	--	129.3	14.
1983	28.4	--	32.1	Peak	--	127.7	14.
1984	28.0	--	31.5	--	--	126.1	14.
1985	27.7	--	31.0	--	--	124.6	14.
1986	27.0	--	30.5	--	--	123.0	Pea
1987	27.0	--	30.0	--	--	121.4	--
1988	27.0	--	29.4	--	--	119.8	--
1989	27.0	--	28.9	--	--	118.3	--

*This company treats Yankee units as purchased power.

†Company share of jointly owned equipment. Full capacity of units i

	(MW)	
Seabrook I	1,150	Vermont Yank
Seabrook 2	1,150	Pilgrim 2
Wyman #4	600	Millstone 3
Yankee Atomic	175	Montague 1
Connecticut Yankee	575	Montague 2
Maine Yankee	769	Sears Island

‡Cumulative Capacity Factor from Nuclear Engineering International,

Base

North Gorham 1-2	Shawmut 1-6	Skelton 1-2	Weston 1-4	Williams 1-2	Wyman Hydro 1-3	Cold Stream	Vermont Yankee	Maine Yankee	Connecticut Yankee	Yankee Atomic-Rowe	Wyman No. 4	Seabrook I
1925	1913-1921	1948	1920-1923	1939-1950	1930-1940	1988	1972*	1972*	1968*	1961*	1978	1983
Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Nuc.	Nuc.	Nuc.	Nuc.	Oil	Nuc.
2	.6	16	12	13	72	83	21†	297†	35†	17†	374†	58†
							VN	MY	CY	YA	CMP	PSNH
							‡	‡	‡	‡		
64.5	100.0	74.0	86.7	91.2	64.0		78.4	74.4	80.1	67.4		
22.2	92.1	64.6	69.5	90.4	68.5						1.8	
10.0	49.9	112.0	89.4	102.5	505.0	--	140.0	1853.8	242.0	97.1	1635.0	--
Intermed.	49.4	112.0	88.3	102.5	505.0	--	140.0	1853.8	242.0	97.1	1635.0	--
--	48.9	112.0	87.3	102.5	505.0	--	140.0	1853.8	242.0	97.1	1635.0	--
--	48.4	112.0	86.2	102.5	505.0	--	140.0	1776.5	230.0	97.1	1635.0	--
--	47.8	112.0	85.2	102.5	505.0	--	140.0	1776.5	230.0	83.2	1635.0	100.8
--	47.3	112.0	84.1	102.5	505.0	--	130.0	1776.5	230.0	83.2	1635.0	201.6
--	46.8	112.0	83.0	102.5	505.0	--	130.0	1699.3	218.0	83.2	1308.0	252.0
--	46.3	112.0	82.0	102.5	505.0	--	130.0	1699.3	218.0	83.2	1308.0	277.2
--	46.0	112.0	Intermed.	102.5	505.0	--	130.0	1699.3	218.0	83.2	1308.0	302.4
--	45.2	112.0	--	102.5	505.0	363.5	130.0	1699.3	218.0	83.2	1308.0	302.4
--	44.7	112.0	--	102.5	505.0	700.0	120.0	1622.0	206.0	83.2	1308.0	302.4

Key:
GT = gas turbine
IC = internal combustion
PSNH = Public Service of New Hampshire
CM = Central Maine
YA = Yankee Atomic
NEU = Northeast Utilities
CY = Connecticut Yankee
MY = Maine Yankee
VN = Vermont Nuclear
BE = Boston Edison
CLP = Connecticut Light and Power
CMP = Central Maine Power Company

2

	Wyman No. 4	Seabrook I	Seabrook 2	Pilgrim 2	Millstone 3	Montague I	Montague 2	Sears Island	Brunswick/ Topsham.	Total for Base Load Equipment
*	1978	1983	1985	1985	1986	1988	1990	1986	1981	
	Oil	Nuc.	Nuc.	Nuc.	Nuc.	Nuc.	Nuc.	Coal	Hydro	
	374†	58†	58†	34†	29†	35†	35†	459†	12	
	CMP	PSNH	PSNH	BE	CLP	NEU	NEU	CMP		
.4										
	1.8									
.1	1635.0	--	--	--	--	--	--	--	--	5165.8
.1	1635.0	--	--	--	--	--	--	--	--	5141.8
.1	1635.0	--	--	--	--	--	--	--	105.0	5200.2
.1	1635.0	--	--	--	--	--	--	--	105.0	5106.3
.2	1635.0	100.8	--	--	--	--	--	--	105.0	5156.6
.2	1635.0	201.6	--	--	--	--	--	--	84.0	5222.2
.2	1308.0	252.0	100.8	60.1	--	--	--	--	105.0	5034.4
.2	1308.0	277.2	201.6	117.7	50.4	--	--	2010.0	105.0	7259.3
.2	1308.0	302.4	252.0	149.1	100.8	--	--	2815.0	105.0	8106.7
.2	1308.0	302.4	277.2	162.1	126.1	60.6	--	3016.0	84.0	8771.3
.2	1308.0	302.4	302.4	177.8	138.7	121.2	--	2975.0	105.0	9100.1

nd Power
Company

Table 6-19

CENTRAL MAINE POWER COMPANY GENERATION BY UNIT
(Millions of Kilowatt-Hours)

1 3

Intermediate

	Automatic I	Bar Mills 1-2	Brunswick A-D	Continental Mills 1-5	Harris 1-3	Oakland	Rice Rips I	Union Gas I	Wyman 1-3	West Buxton 3-6	Bonny Eagle 1-6	North Gorham 1-2	Milstar I	Weston 1-4	Total for Intermediate
Startup date	1924	1956	1908-1911	1920	1954	1924	1918	1935	1957-1965	1904-1927	1910	1925	1974	1920-1923	
Fuel	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Oil	Hydro	Hydro	Hydro	Hydro	Hydro	
Rating (MW)	1	5	26	2	75	3	2	1	209	7	7	2	5	12	
Capacity factor (%)															
1977		57.7	50.4	33.3	37.0	39.2	47.3	40.0	36.9	47.8	From	From	From	From	
1978		51.1	34.1	30.1	40.4	36.7	37.1		42.2	41.4	Base	Base	Base	Base	
Generation ($kWh \times 10^9$)															
1979	4.4	21.9	79.7	8.8	260.0	13.0	7.0	3.0	823.0	30.7	Base	Base	Base	Base	12
1980	Peak	21.0	91.1	Peak	260.0	13.0	7.0	3.0	805.5	30.0	"	7.0	"	"	12
1981	--	21.0	91.1	--	260.0	13.0	7.0	3.0	787.3	Peak	24.5	6.8	"	"	12
1982	--	21.0	91.1	--	260.0	13.0	7.0	3.0	768.9	--	24.0	6.6	"	"	11
1983	--	21.0	91.0	--	260.0	13.0	Peak	3.0	750.7	--	23.0	6.4	"	"	11
1984	--	21.0	Peak	--	260.0	13.0	--	3.0	732.3	--	22.0	6.2	"	"	10
1985	--	21.0	--	--	260.0	Peak	--	Peak	88MW to peak 445.0	--	21.0	6.0	"	"	7
1986	--	Peak	--	--	260.0	--	--	--	434.6	--	20.0	5.8	"	"	7
1987	--	--	--	--	260.0	--	--	--	424.0	--	19.0	5.6	4.4	4.2	7
1988	--	--	--	--	260.0	--	--	--	413.3	--	19.0	5.5	4.0	4.0	7
1989	--	--	--	--	260.0	--	--	--	402.8	--	18.4	5.3	3.8	3.7	6

1

Cape 4-5	Farmingdale I	Mason I	Mason 2	Mason 3	Mason 4	Mason 5	Automatic I	Bar Mills 1-2	Brunswick A-D	East Rips 1-7	Fort Halifax	Rockland	Hiram 1	Oakland	Rips Rips	Union Gas
NA	1950	1942	1947	1952	1952	1955	1924	1956	1908-1911	1913-1924	1908	1948	1917	1924	1918	[illegible]
GT	GT	Oil	Oil	Oil	Oil	Oil	Hydro	Hydro	Hydro	Hydro	Hydro	Oil-IC	Hydro	Hydro	Hydro	[illegible]
34	4	20	20	33	33	33	1	5	26	6	2	2	2	3	2	[illegible]
0.3		15.7	15.7	15.7	15.7	15.7	From	From	From	From	From		From	From	From	[illegible]
0.3	0.1	2.9	2.9	2.9	2.9	2.9	Int.	Int.	Int.	Base	Base	0.5	Base	Int.	Int.	[illegible]
6.0	1.1	Retire	28.0	50.0	50.0	50.0	Int.	Int.	Int.	Base	Base	3.0	Base	Int.	Int.	[illegible]
6.0	1.1	--	28.0	50.0	50.0	50.0	2.0	"	"	"	5.0	3.0	"	"	"	
6.0	1.1	--	28.0	50.0	50.0	50.0	2.0	"	"	"	5.0	3.0	"	"	"	
6.0	1.1	--	28.0	50.0	50.0	50.0	2.0	"	"	"	5.0	3.0	"	"	"	
6.0	1.1	--	28.0	50.0	50.0	50.0	2.0	"	"	10.5	5.0	3.0	"	"	5.0	
6.0	1.1	--	Retire	50.0	50.0	50.0	2.0	"	68.3	10.5	5.0	3.0	"	"	5.0	
6.0	1.1	--	--	50.0	50.0	50.0	2.0	"	68.3	10.5	5.0	3.0	"	7.0	5.0	
6.0	1.1	--	--	50.0	50.0	50.0	2.0	17.5	68.3	10.5	5.0	3.0	3.5	7.0	5.0	
6.0	1.1	--	--	Retire	50.0	50.0	2.0	17.5	68.3	10.5	5.0	3.0	3.5	7.0	5.0	
6.0	1.1	--	--	--	Retire	50.0	2.0	17.5	68.3	10.5	5.0	3.0	3.5	7.0	5.0	
6.0	1.1	--	--	--	--	50.0	2.0	17.5	68.3	10.5	5.0	3.0	3.5	7.0	5.0	

2

	Fort Halifax	Rockland	Hiram I	Oakland	Rice Rips	Union Gas	Wyman I-2	West Buxton 3-6	Continental Mills 1-5	Peaks Island 1, 2, 5	Total for Peak Load Equipment	Total System Generation
	1908	1948	1917	1924	1918	1935	1957-1965	1904-1927	1920	1940-1948		
o	Hydro	Oil-IC	Hydro	Hydro	Hydro	Hydro	Oil	Hydro	Hydro	Oil-IC		
	2	2	2	3	2	1	88	7	2	3		
m e	From Base	0.5	From Base	From Int.	From Int.	From Int.	From Int. 88MW only	From Int.	From Int.	1.1		
e	Base	3.0	Base	Int.	Int.	Int.	Int.	Int.	Int.	6.0	220.1	6637.4
	5.0	3.0	"	"	"	"	"	"	5.0	6.0	230.1	6609.5
	5.0	3.0	"	"	"	"	"	12.5	5.0	6.0	240.6	6654.5
	5.0	3.0	"	"	"	"	"	12.5	5.0	6.0	218.6	6519.5
.5	5.0	3.0	"	"	5.0	"	"	12.5	5.0	6.0	234.1	6588.8
.5	5.0	3.0	"	"	5.0	"	"	12.5	5.0	6.0	274.4	6554.1
.5	5.0	3.0	"	7.0	5.0	2.5	15.5	12.5	5.0	6.0	299.4	6086.8
.5	5.0	3.0	3.5	7.0	5.0	2.5	15.5	12.5	5.0	6.0	320.4	8300.1
.5	5.0	3.0	3.5	7.0	5.0	2.5	15.5	12.5	5.0	6.0	270.4	9094.3
.5	5.0	3.0	3.5	7.0	5.0	2.5	15.5	12.5	5.0	6.0	220.4	9697.5
.5	5.0	3.0	3.5	7.0	5.0	2.5	15.5	12.5	5.0	6.0	220.4	10014.5

Table 6-19

CENTRAL MAINE POWER COMPANY: GENERATION BY UNIT
(Millions of Kilowatt-Hours)
(Concluded)

3

Base

	Brayton Pt.3	Brayton Pt.4 (Cycling capability)	Vermont Yankee	Maine Yankee	Conn. Yankee	Yankee Atomic	Deerfield 2	Deerfield 3	Deerfield 4	McIndoes 1-4	Bellows Falls 1-3	Searsburg 1	Vernon 1-10	Wilder 1-2
Location	MA	MA	VT	ME	CN	MA	MA	MA	MA	NH	VT	VT	VT	VT
Startup date	1969	1974	1972	1972	1968	1961	1913	1912	1913	1931	1928	1922	1922	1950
Fuel	Coal	Coal	Nuc.	Nuc.	Nuc.	Nuc.	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro	Hydro
Rating (MW)	640	476	106*	156*	86*	53*	5	5	5	11	41	4	24	32
Owner	NEP	NEP	VY	MY	CY	YA	NEP	NEP	NEP	NEP	NEP	NEP	NEP	NEP
Capacity Factor (%)			‡	‡	‡	‡								
1976	55.0	64.0					59.5	64.3	61.9	63.3	83.8	80.0	68.7	65.5
1977	56.3	65.0	75.0	81.0	76.0	61.7	55.5	64.8	63.1	54.3	68.9	73.4	57.5	56.0
Generation (kWh x 10^9)														
1977 (approx.)	3.10	2.69	0.70	1.11	0.57	0.29	0.02	0.03	0.03	0.05	0.25	0.02	0.12	0.16
1978	3.34	2.67	0.70	1.11	0.57	0.29	0.02	0.03	0.03	0.05	0.25	0.02	0.11	0.15
1979	3.29	2.62	0.70	1.11	0.57	0.29	0.02	0.03	0.03	0.05	0.25	0.02	0.10	0.14
1980	3.23	2.59	0.70	1.11	0.57	0.29	0.02	0.03	0.03	Int.	0.24	0.02	Int.	Int.
1981	3.18	2.54	0.70	1.11	0.57	0.29	0.02	0.02	0.03	--	0.24	0.02	--	--
1982	3.12	2.50	0.70	1.10	0.56	0.29	0.02	Int.	0.02	--	0.24	0.02	--	--
1983	3.06	2.46	0.70	1.10	0.56	0.28	Int.	--	Int.	--	0.23	0.02	--	--
1984	3.01	2.42	0.69	1.10	0.56	0.28	--	--	--	--	0.23	0.02	--	--
1985	2.95	2.38	0.69	1.09	0.55	0.28	--	--	--	--	0.23	0.02	--	--
1986	2.89	2.34	0.69	1.09	0.55	0.28	--	--	--	--	Int.	Int.	--	--
1987	2.84	2.29	0.69	1.09	0.55	0.28	--	--	--	--	--	--	--	--
1988	2.78	2.25	0.69	1.09	0.55	0.28	--	--	--	--	--	--	--	--
1989	2.73	2.21	0.68	1.08	0.54	0.28	--	--	--	--	--	--	--	--

Key: PS = pumped storage
IC = internal combustion
GT = gas turbine
NEP = New England Power Company
NEC = Narragansett Electric Company

PSNH = Public Service of New Hampshire
BE = Boston Edison
CLP = Connecticut Light and Power
NEU = Northeast Utilities
CMP = Central Maine Power Company
VN = Vermont Nuclear
MY = Maine Yankee
CY = Connecticut Yankee
YA = Yankee Atomic

*Company share

Vermont Yankee
Maine Yankee
Conn. Yankee
Yankee Atomic
Wyman #4
Seabrook I

†Cumulative cap

1

Wilder 1-2	Wyman 4	Salem Harbor 3	Salem Harbor 4 (cycling capability)	Seabrook I	Seabrook 2	Pilgrim 2	Millstone 3	Montague I	NEPCO I Charleston	NEPCO 2 Charleston	Total for Base Load Equipment
VT	ME	MA	MA	NH	NH	MA	CT	MA	RI	RI	
1950	1978	1958	1972	1983	1985	1985	1986	1988	1986	1988	
Hydro	Oil	Oil	Oil	Nuc.	Nuc.	Nuc.	Nuc.	Nuc.	Nuc.	Nuc.	
32	56	156	482	115*	115*	130*	138*	150*	909*	909*	
NEP	CM	NEP	NEP	PSNH	PSNH	BE	CLP	NEU	NEP	NEP	
65.5	--	52.5	59.0								
56.0	1.8	45.7	58.0								
0.16	--	0.61	2.43	--	--	--	--	--	--	--	12.18
0.15	0.005	0.55	2.74	--	--	--	--	--	--	--	12.64
0.14	0.04	Int.	2.69	--	--	--	--	--	--	--	11.95
Int.	0.04	--	2.65	--	--	--	--	--	--	--	11.52
--	0.04	--	2.61	--	--	--	--	--	--	--	11.37
--	0.04	--	2.57	--	--	--	--	--	--	--	11.18
--	0.04	--	2.53	0.2	--	--	--	--	--	--	11.18
--	0.04	--	2.48	0.4	--	--	--	--	--	--	11.23
--	0.03	--	2.44	0.5	0.2	0.23	--	--	--	--	11.59
--	0.03	--	2.40	0.55	0.4	0.45	0.24	--	1.57	--	13.48
--	0.03	--	2.36	0.6	0.5	0.57	0.48	--	3.13	--	15.41
--	0.03	--	2.31	0.6	0.55	0.62	0.60	0.26	3.91	1.57	18.09
--	0.03	--	2.27	0.6	0.6	0.68	0.66	0.52	4.30	3.13	20.31

ny share of jointly owned equipment. Full capacity of units is as follows:

	MW		MW
ont Yankee	528	Seabrook 2	1,150
e Yankee	769	Pilgrim 2	1,180
. Yankee	575	Millstone 3	1,150
ee Atomic	175	Montague I	1,150
n #4	355	Nepco I	1,150
rook I	1.150	Nepco 2	1,150

lative capacity factor from Nuclear Engineering International (April 1978).

Table 6-20

NEW ENGLAND ELECTRIC SYSTEM:
GENERATION BY UNIT
(Billions of kWh)

2

										Intermediate			
	Brayton Pt. I	Brayton Pt. 2	Deerfield 2	Deerfield 3	Deerfield 4	Deerfield 5	Fifebrook I	Salem Harbor 1	Salem Harbor 2	Salem Harbor 3	Sherman I	Comerford 1-4	[illegible]
Location	MA	MA	MA	MA	MA	MA	MA	MA	MA	MA	MA	NH	N
Startup date	1963	1964	1913	1912	1913	1974	1974	1951	1952	1958	1927	1930	1
Fuel	Coal	Coal	Hydro	Hydro	Hydro	Hydro	Hydro	Oil	Oil	Oil	Hydro	Hydro	Hy
Rating (MW)	261	261	5	5	5	18	11	82	82	156	7	140	11
Owner	NEP	NEP	NEP	NEP	NEP	NEP	NEP	NEP	NEP	NEP	NEP	NEP	N
Capacity Factor (%)													
1976	33.8	33.8	From	From	From	33.8	38.4	37.0	37.0	From	58.8	32.0	Fr
1977	43.7	43.7	base	base	base	33.8	38.7	35.1	35.1	base	49.3	29.3	ba
Generation (kWh x 10^{12})													
1977 (approx.)	0.90	0.90	Base	Base	Base	0.05	0.04	0.25	0.25	--	0.03	0.36	Ba
1978	1.07	1.07	"	"	"	0.05	0.04	0.22	0.22	--	0.03	0.49	[illegible]
1979	1.05	1.05	"	"	"	0.05	0.04	Peak	0.19	0.53	0.03	0.49	[illegible]
1980	1.02	1.02	"	"	"	0.05	0.04	--	Peak	0.52	0.03	0.49	[illegible]
1981	1.00	1.00	"	"	"	0.05	0.04	--	--	0.51	0.03	0.49	[illegible]
1982	0.98	0.98	"	0.02	"	0.05	0.04	--	--	0.49	0.03	0.49	[illegible]
1983	0.96	0.96	0.02	0.02	0.02	0.04	0.04	--	--	0.48	0.02	0.49	[illegible]
1984	0.93	0.93	0.02	0.02	0.02	0.04	0.04	--	--	0.46	0.02	0.49	[illegible]
1985	0.91	0.91	0.02	0.02	0.02	0.04	0.04	--	--	0.45	0.02	0.49	[illegible]
1986	0.89	0.89	0.02	0.02	0.02	0.04	0.04	--	--	0.44	Peak	0.49	[illegible]
1987	0.86	0.86	0.02	0.02	0.02	0.04	0.04	--	--	0.42	--	0.49	[illegible]
1988	0.84	0.84	0.02	0.02	0.02	0.04	0.04	--	--	0.41	--	0.49	[illegible]
1989	0.82	0.82	0.02	0.02	0.02	0.03	0.04	--	--	0.40	--	0.49	[illegible]

Key: PS = pumped storage
IC = internal combustion
GT = gas turbine
NEP = New England Power Company
NEC = Narragansett Electric Company
PSNH = Public Service of New Hampshire
BE = Boston Edison
CL&P = Connecticut Light and Power
NEU = Northeast Utilities
CM = Central Maine Power Company

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	Sherman I	Comerford 1-4	McIndoes 1-4	Moore 1-4	South Street	Bellows Falls 1-3	Harriman 1-3	Searsburg I	Vernon 1-10	Wilder 1-2	Total for Int. Load Equipment
	MA	NH	NH	NH	RI	VT	VT	VT	VT	VT	
8	1927	1930	1931	1956	NA	1928	1924	1922	1922	1950	
	Hydro	Hydro	Hydro	Hydro	Oil	Hydro	Hydro	Hydro	Hydro	Hydro	
	7	140	11	140	111	41	34	4	24	32	
	NEP	NEP	NEP	NEP	NEC	NEP	NEP	NEP	NEP	NEP	
				20.0							
	58.8	32.0	From	28.7	29.4	From	41.8	From	From	From	
	49.3	29.3	base	25.3	37.4	base	41.8	base	base	base	
	0.03	0.36	Base	0.31	0.36	Base	0.12	Base	Base	Base	2.35
	0.03	0.49	"	0.49	0.41	"	0.12	"	"	"	4.22
53	0.03	0.49	"	0.49	0.40	"	0.12	"	"	"	4.45
52	0.03	0.49	0.04	0.49	0.39	"	0.11	"	0.10	0.13	4.49
51	0.03	0.49	0.04	0.49	0.38	"	0.11	"	0.10	0.13	4.38
49	0.03	0.49	0.04	0.49	0.37	"	0.11	"	0.10	0.13	4.33
48	0.02	0.49	0.04	0.49	0.36	"	0.10	"	0.10	0.12	4.27
46	0.02	0.49	0.04	0.49	0.35	"	0.10	"	0.10	0.12	4.18
45	0.02	0.49	0.04	0.49	0.34	"	0.10	"	0.10	0.12	4.12
44	Peak	0.49	0.04	0.49	0.33	0.21	0.10	0.02	0.10	0.12	4.27
42	--	0.49	0.04	0.49	0.32	0.21	0.09	0.02	0.10	0.12	4.17
41	--	0.49	0.04	0.49	0.31	0.21	0.09	0.01	0.10	0.11	4.09
40	--	0.49	0.04	0.49	0.31	0.21	0.09	0.01	0.10	0.11	4.02

Table 6-20

NEW ENGLAND ELECTRIC SYSTEM
GENERATION BY UNIT
(Billions of kWh)
(Continued)

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	Peak												
	Bear Swamp I	Bear Swamp 2	Brayton Pt. IC 1-4	Gloucester 1-11	Lynnway 1-8	Newburyport 1-4	Salem Harbor I	Salem Harbor 2	Sherman I	Uxbridge GT 1-2	Manchester St. 9	Manchester St. 10	Manchester St.
Location	MA	MA	MA	MA	MA	MA	MA	MA	MA	MA	RI	RI	RI
Startup date	1974	1974	1967	1963-70	1970	1970	1951	1952	1927	1971	1941	1947	19
Fuel	PS	PS	IC	IC	IC	IC	Oil	Oil	Hydro	GT	Oil	Oil	Oi
Rating (MW)	300	300	11	28	24	12	82	82	7	40	40	46	46
Owner	NEP	NEP	NEP	NEP	NEP	NEP	NEP	NEP	NEP	NEP	NEC	NEC	N
Capacity Factor (%)													
1976	4.9	4.9	2.3	5.3	3.3	2.9	From	From	From	1.2			
1977	4.3	4.3	3.1	8.6	2.9	2.8	Int.	Int.	Int.	1.7	14.0	18.0	18
Generation (kWh x 10^{12})													
1977 (approx.)	0.11	0.12	0.003	0.02	0.006	0.003	Int.	Int.	Int.	.006	0.05	0.07	0
1978	0.12	0.12	0.003	0.02	0.01	0.003	"	"	"	.005	0.02	0.04	0
1979	0.12	0.12	0.003	0.02	0.01	0.003	0.22	"	"	.005	Retd.	0.03	0
1980	0.12	0.12	0.003	0.02	0.01	0.003	0.21	0.21	"	.005	--	0.02	0
1981	0.12	0.12	0.003	0.02	0.01	0.003	0.20	0.20	"	.005	--	0.01	0
1982	0.12	0.12	0.003	0.02	0.01	0.003	0.19	0.19	"	.005	--	Retd.	0
1983	0.12	0.12	0.003	0.02	0.01	0.003	0.19	0.19	"	.005	--	--	0
1984	0.12	0.12	0.003	0.02	0.01	0.003	0.18	0.18	"	.005	--	--	R
1985	0.12	0.12	0.003	0.02	0.01	0.003	0.17	0.17	"	.005	--	--	-
1986	0.12	0.12	0.003	0.02	0.01	0.003	Retd.	0.16	0.01	.005	--	--	-
1987	0.12	0.12	0.003	0.02	0.01	0.003	--	Retd.	0.01	.005	--	--	-
1988	0.12	0.12	0.003	0.02	0.01	0.003	--	--	0.01	.005	--	--	-
1989	0.12	0.12	0.003	0.02	0.01	0.003	--	--	0.01	.005	--	--	-

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Salem Harbor 2	Sherman I	Uxbridge GT 1-2	Manchester St. 9	Manchester St. 10	Manchester St. 11	South Street	Total for Peak Load Equipment	Total for the System
MA	MA	MA	RI	RI	RI	RI		
1952	1927	1971	1941	1947	1949	NA		
Oil	Hydro	GT	Oil	Oil	Oil	Oil		
82	7	40	40	46	46	6		
NEP	NEP	NEP	NEC	NEC	NEC	NEC		
From	From	1.2				1.7		
Int.	Int.	1.7	14.0	18.0	18.0	2.1		
Int.	Int.	.006	0.05	0.07	0.07	.001	0.459	14.99
"	"	.005	0.02	0.04	0.04	.001	0.382	17.24
"	"	.005	Retd.	0.03	0.03	.001	0.562	16.96
0.21	"	.005	--	0.02	0.02	.001	0.742	16.70
0.20	"	.005	--	0.01	0.02	.001	0.712	16.46
0.19	"	.005	--	Retd.	0.01	.001	0.672	16.18
0.19	"	.005	--	--	0.01	.001	0.672	16.12
0.18	"	.005	--	--	Retd.	.001	0.642	16.05
0.17	"	.005	--	--	--	.001	0.622	16.33
0.16	0.01	.005	--	--	--	.001	0.452	18.20
Retd.	0.01	.005	--	--	--	.001	0.292	19.87
--	0.01	.005	--	--	--	.001	0.292	22.47
--	0.01	.005	--	--	--	.001	0.292	24.62

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Table 6-20

NEW ENGLAND ELECTRIC SYSTEM:
GENERATION BY UNIT
(Billions of kWh)
(Concluded)

1 2

Table 6-21

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE
GENERATION BY FUEL TYPE

Year	Generation (kWh X10^9)	Proportion of Generation (Percent) Nuclear	Coal	Oil	Distillate	Hydropower	Total
1979	4.75	13.7	39.9	40.2	0.1	6.1	100.0
1980	4.64	14.0	38.8	40.8	0.1	6.3	100.0
1981	4.43	14.7	38.4	40.2	0.1	6.6	100.0
1982	4.39	14.4	38.7	40.2	0.1	6.6	100.0
1983	4.67	21.9	36.4	35.4	0.1	6.2	100.0
1984	5.05	27.9	33.7	32.5	0.1	5.8	100.0
1985	5.49	36.3	29.2	29.2	0.1	5.2	100.0
1986	5.82	42.8	26.5	25.6	0.1	5.0	100.0
1987	6.06	46.1	24.8	24.3	0.1	4.7	100.0
1988	6.05	47.7	23.1	24.3	0.1	4.8	100.0
1989	5.96	49.6	23.5	22.0	0.1	4.8	100.0

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A FEASIBILITY STUDY OF WINDPOWER FOR THE NEW ENGLAND AREA.(U)
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Table 6-22

CENTRAL MAINE POWER COMPANY
GENERATION BY FUEL TYPE

Year	(KWh X10^6)	Proportion of Generation (Percent)					
		Nuclear	Coal	Oil	Distillate	Hydropower	Total
1979	6,637	35.2	-	40.2	0.1	24.5	100.0
1980	6,610	35.3	-	40.1	0.1	24.5	100.0
1981	6,655	35.1	-	39.5	0.1	25.3	100.0
1982	6,520	34.4	-	39.7	0.1	25.7	100.0
1983	6,589	35.4	-	39.0	0.1	25.0	100.0
1984	6,554	36.9	-	38.5	0.1	24.4	100.0
1985	6,086	41.8	-	31.7	0.1	26.4	100.0
1986	8,299	33.5	24.2	23.1	0.1	19.1	100.0
1987	9,094	32.3	31.0	20.4	0.1	16.2	100.0
1988	9,697	31.5	31.1	18.5	0.1	18.8	100.0
1989	10,015	30.7	29.7	17.8	0.1	21.7	100.0

Table 6-23

NEW ENGLAND ELECTRIC SYSTEM
GENERATION BY FUEL TYPE

Year	Total (kWh X10^9)	Proportion of Generation (Percent) Nuclear	Coal	Oil	Distillate	Hydropower	Total
1978	17.24	15.5	47.3	24.9	0.03	12.3	100.0
1979	16.96	15.8	47.2	24.6	0.03	12.4	100.0
1980	16.70	16.0	47.1	24.6	0.03	12.3	100.0
1981	16.46	16.2	46.9	24.4	0.03	12.5	100.0
1982	16.18	16.4	46.9	24.1	0.03	12.6	100.0
1983	16.12	17.6	46.2	23.8	0.03	12.4	100.0
1984	16.05	18.9	45.5	23.2	0.03	12.4	100.0
1985	16.33	21.7	43.8	22.3	0.03	12.2	100.0
1986	18.20	32.0	38.5	18.7	0.03	10.8	100.0
1987	19.87	39.7	34.5	16.0	0.03	9.8	100.0
1988	22.47	47.7	29.9	13.8	0.02	8.6	100.0
1989	24.62	53.1	26.7	12.4	0.02	7.8	100.0

Other Naval activities in the region include the Naval Communication Unit at Cutler, Maine; the Security Group Activity at Winter Harbor, Maine; the Naval Air Stations at Brunswick, Maine, and South Weymouth, Maine; the Naval Education and Training Center at Newport, Rhode Island, and the nearest other submarine docking and repair facilities, which are at the submarine base in New London, Connecticut. Pease Air Force Base, in nearby Portsmouth, New Hampshire, provides Commissary, Exchange, and other personnel support services to the Shipyard.

The Shipyard encompasses about 278 acres (111.2 hectares) of land including the noncontiguous 25-acre (10-hectare) family housing site. The base has three drydocks ranging up to SSBN and SSN-688 class capability and 5,500 lineal ft (1,650 m) of berthing. The berthing is effectively composed of six submarine berths of varying class capability, ranging from only parking capability with no services to repair berths with near total repair and test capabilities, plus berths for yard and service craft. In addition, the base has 376 buildings and structures with 3,560,000 ft ($320,400\ m^2$) of floor space.

Total personnel for all activities include 181 officers, 1,097 enlisted personnel, and 7,655 civilians during late 1977.

The Shipyard produces steam at a central plant, for the heating of buildings, for hot water converters, and for service to submarines and craft at berths and in the drydocks. Electric power is also generated: the generators are primarily base loaded to obtain the most effective mix between generated and purchased power. In addition, generators are used for peak shaving and reliability because PSNH cannot provide the entire electric power requirements through their service feeders.

The steam boilers have a combined rated capacity of 510,000 lb/hr (229,500 kg/hr). In-house generating capability includes two 3,500-kW steam turbines that are about 33 years old and a recently installed 7,500 kW steam turbine.

Two submarine cable ties, each rated at 300 amps, or 7,000 kilovolt-amperes (kVA) at 13.5 kV connect the Shipyard to the commercial system at Portsmouth, New Hampshire, and these are connected to the New England power grid. Under normal conditions, a maximum of 8,000 kVA can be purchased, and, if the power is available, PSNH will provide up to a maximum of 10,000 kVA under prearranged conditions.

Fuel for the base system currently consists of No. 6 fuel oil, trucked in as required and stored in ready issue tanks at the power plant. Backup storage of 150,000 bbl is maintained.

The Shipyard plans to continue central steam production together with electrical power purchase, with some self-generation, at whatever levels are most cost-effective for the Shipyard.

Annual consumption of electric power at the Shipyard is about 60×10^6 kWh at a cost of 3.0-3.5¢/kWh. The present daily peak demand varies between 11,000 and 14,000 kVA; 2-7 MW of this demand is purchased from the local utility, and the remainder is provided by the Shipyard's power plant as necessary.

The currently scheduled known shipyard workload for FY 1978 through 1983 includes:

(1) Selected restricted availability: 19 nuclear-powered submarines

(2) Restricted availability: 2 nuclear-powered submarines

(3) Regular overhaul: 16 nuclear-powered submarines.

Shipyard officials predict that the substantial increase in berthing facilities for submarines, planned personnel support and facilities construction, and the anticipated assignment of SSN 688 class submarines to the yard will increase the demand for electric power far beyond the capacity of the present commercial utility source. They estimate that future consumption of electrical energy will range between 73×10^6 and 82×10^6 kWh and that daily peak demand will increase to 18,000-20,000 kVA in the near future.

Table 6-24 shows the steady growth in fuel oil consumption in recent years and the explosive increase in fuel oil costs. Table 6-25 shows the seasonal variation, with monthly consumption during the cold winter months exceeding summer monthly consumption by a factor of about three.

In September 1978, the price of fuel oil to the Shipyard was 31.5¢/gal, and it increased to 36.5¢/gal in June 1979. For economic projections, the shipyard has assumed that the fuel oil price will rise to 50¢/gal.

Figure 6-1 shows monthly electrical energy generation and procurement levels and annual totals, as well as the weekly variation in peak power demand placed by the Shipyard on PSNH for the period January 1978 to June 1979. The figure indicates a gradual downward trend in electrical energy generation at the Shipyard and a slight upward trend in electrical energy purchases (from the utility), resulting in a slight downward trend in total electrical use (generated plus purchased). The rough average

Table 6-24

PORTSMOUTH NAVAL SHIPYARD
FUEL OIL CONSUMPTION SUMMARY, 1964-1978
(Gallons)

	Quantity of Fuel	Cost ($)
1964	9,842,340	515,616.90
1965	8,902,771	509,461.34
1966	8,851,200	518,349.45
1967	8,999,355	464,280.76
1968	8,765,894	425,023.45
1969	9,015,065	433,372.84
1970	8,979,006	421,565.32
1971	9,205,458	811,836.03
1972	9,298,755	782,086.68
1973	8,673,455	699,582.81
1974	7,954,219	2,165,143.16
1975	8,154,855	2,242,426.16
1976	9,521,460	2,593,242.08
1977	10,629,649	3,560,429.34
1978	10,424,071	3,312,896.13

Table 6-25

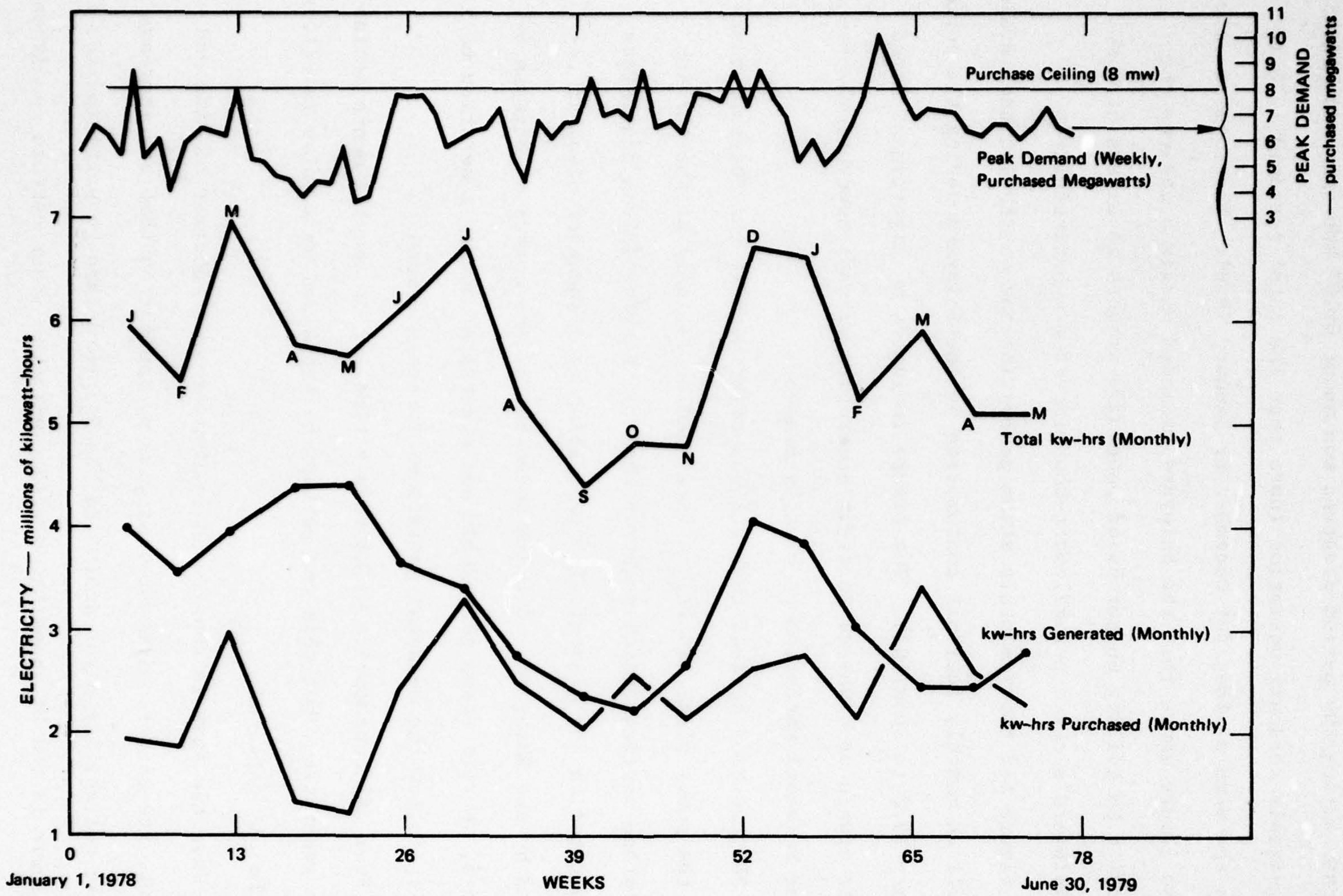
PORTSMOUTH NAVAL SHIPYARD
MONTH-BY-MONTH FUEL OIL CONSUMPTION, 1976-1979
(Gallons)

1976	Quantity
January	959,410
February	1,361,240
March	998,630
April	868,666
May	676,670
June	595,968
July	428,352
August	447,804
September	479,787
October	667,525
November	1,002,037
December	1,035,371
Total	9,521,460

1977	Quantity
January	1,292,700
February	1,330,098
March	1,141,868
April	1,066,552
May	884,634
June	545,840
July	483,175
August	604,975
September	571,025
October	740,553
November	815,008
December	1,153,221
Total	10,629,649

1978	Quantity
January	1,265,856
February	1,290,476
March	1,241,121
April	1,082,945
May	912,859
June	670,948
July	436,968
August	525,722
September	626,073
October	560,448
November	776,220
December	1,034,435
Total	10,424,071

1979	Quantity
January	1,224,679
February	1,368,166
March	1,056,564
April	855,601
May	653,960
June	523,236



SOURCE: Public Works Department, Portsmouth Naval Shipyard.

FIGURE 6-1 PURCHASED AND GENERATED ELECTRICITY, PORTSMOUTH NAVAL SHIPYARD — JANUARY 1978 TO JUNE 1979

use rate during the period observed was about $6x10^6$ kWh/ mo, with little recognizable seasonal variation (note that the total for July 1978 is about the same as that for December or January 1979). The topmost curve on the figure shows that the Shipyard exceeded on six occasions the nominal 8 MW ceiling on purchased power (for amounts in excess of 8 MW, the Shipyard's costs per kilowatt-hour increase substantially).

Figure 6-2 shows monthly steam generation and on-station use levels, as well as monthly fuel oil consumption by the Shipyard during the period January 1978 to June 1979. The figure indicates no significant trend either upward or downward in steam generation or use; however, the expected seasonal variation is clearly present.

SRI has been advised that all the steam used at the Shipyard (outside the power plant itself) is extracted at 195 psig at the turbine interstage section, which requires that the turbine-driven generators be operated in the economical cogeneration mode whenever steam is required by the Shipyard. This is borne out by the curves of Figures 6-1 and 6-2, wherein steam generation and electrical energy generation both closely follow the seasonal variations in steam demand.

Fuel oil consumption peaks show a time lag of about 1 month behind steam generation, but this can perhaps be explained by a delay in billings for the oil consumed.

When the Navy is considered in context as a customer of PSNH and NEPOOL, its user requirement data give no indication that any increase in supply reliability might accrue to the Shipyard through participation in windpower in the Mt. Washington area. Although under certain conditions

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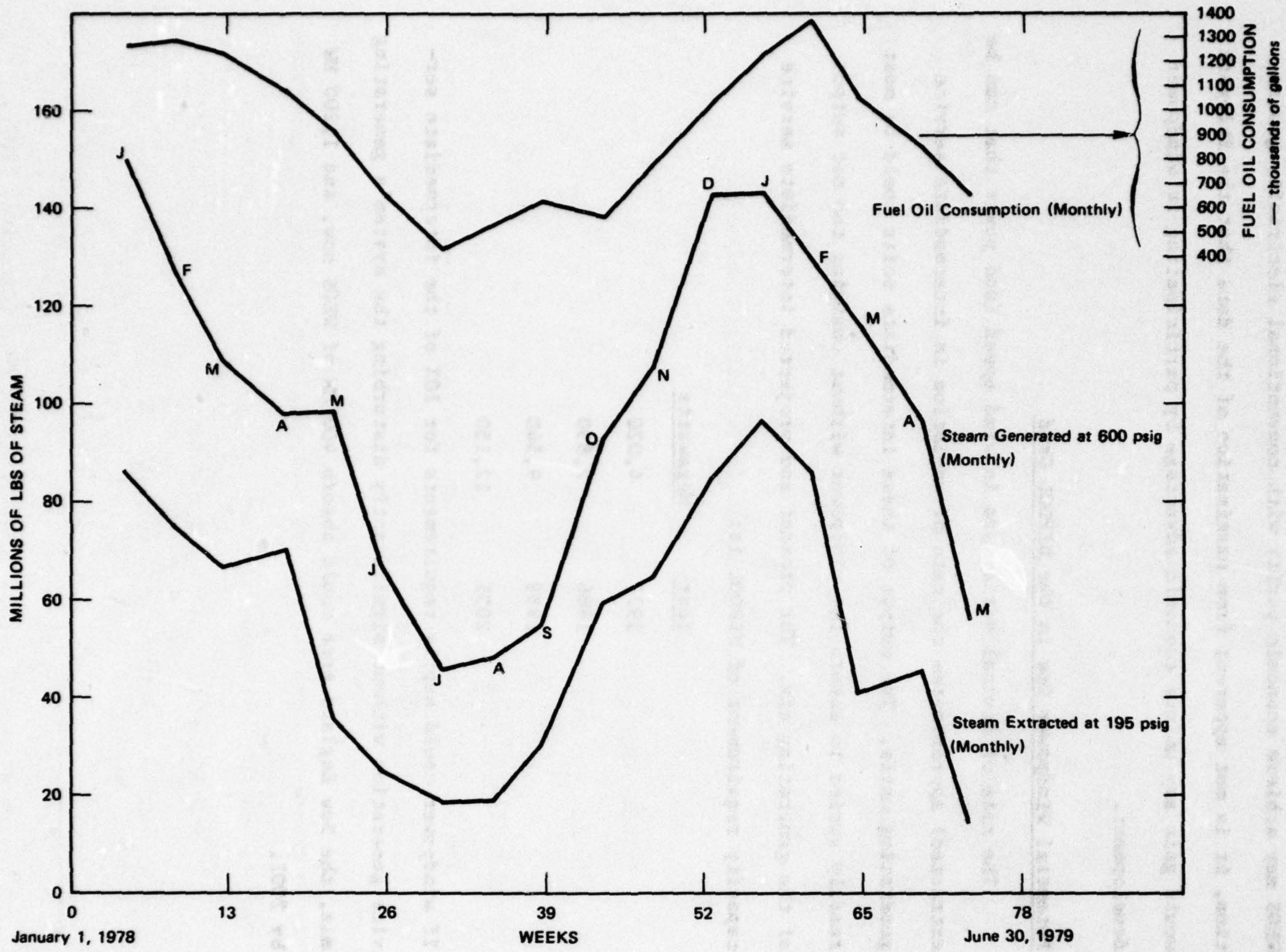

SOURCE: Public Works Department, Portsmouth Naval Shipyard.

FIGURE 6-2 STEAM AND FUEL OIL USE, PORTSMOUTH NAVAL SHIPYARD — JANUARY 1978 TO JUNE 1979

WEGS may achieve economic parity with conventional electricity generation, it is not apparent from examination of the data that the Shipyard would gain any unique economic advantage by participating in windpower development.

Potential Windpower Use in the NEPOOL Grid

The rate of diurnal variations in wind speed (and power that can be extracted) approximates the rate of variation in intermediate service generating units. The output of these intermediate units could be most readily varied to absorb the windpower without changing the net output of the generating mix. The present and projected intermediate service capacity requirement of NEPOOL is:

Year	Megawatts
1977	4,020
1986	7,830
1989	9,540
2001	12,150

If windpower could supply requirements for 10% of the intermediate service generation without significantly disturbing the system's generating mix, the New England area could absorb 400 MW of WEGS now, and 1,200 MW by 2001.

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7. TECHNOLOGY STATUS REVIEW

Summary

The Boeing MOD 2 design was analyzed in this research effort because it is representative of achievable technology, and its performance and economics can be credibly estimated. The constant speed, variable pitch, two-bladed rotor, speed increaser gear box, and 1,800-rpm synchronous 60-Hz generator combination used in this design is representative of large wind energy generating systems (WEGS) in general. Other, less fully developed WEGS designs might have efficiency, cost, or other advantages. SRI conducted a limited review of the technology status of other WEGS designs.

Wind turbine designs with a high probability of commercial production in the near future are summarized in Table 7-1. All costs have been updated to 1979 dollars and are based on the manufacturers' projected costs. The cents per kilowatt hour figure has also been calculated by the manufacturer and is associated with a wind speed at a 30-ft (9.3 m) height.

Technology Status

The development of the MOD 2 has significantly reduced the cost of large horizontal axis wind turbines (HAWT). However, additional design improvements now under investigation may further decrease costs of electricity from wind generators. These include:

Table 7-1

COMPARISON OF WEGS WITH HIGH COMMERCIAL POTENTIAL
(1979 Dollars)

	Installed Cost ($x10^6)	Power Rating (MW)	$/kW	Rated Speed (mph)	Diameter (feet)	Cut-in* (mph)	Cut-out* (mph)	Annual Output† (MWh) 12 mph	15 mph	18 mph	20 mph	Designer Energy Cost (¢/kWh) 12 mph	15 mph	18 mph	20 mph	Stage of Development
MOD 0A (Westinghouse)	0.241	0.200	$1,206	21.7	125	10/12	35/40	600	900	1,100	1,200					In production
MOD 0A (50 kW, Westinghouse)	1.050	0.050	2,100	18.3		10	44			1,800				<12		In production
MOD 1A (G.E.)	2.00	2.00	1,000	25	200	11	35	2,500	5,000	6,800	8,000			5-6		Prototype available
MOD 2 (Boeing 25 unit cluster	2.04	2.50	816	27.5	300	13/14	42/45	7,200	10,000	13,600	14,200	5.5	3.8‡	2.5		Prototype in 80
Two-blade Darrieus (Alcoa)	0.170§	0.300	570		123/82■		60	325	625	935			3-5			Commercially available
Three-blade Darrieus (Alcoa)	0.190§	0.500	380		123/82■		60	265	635	1,125				2-4		Commercially available
Shachle Design (Wind Power Products)	1.00	3.00	333	40	165		40									Prototype in 79
Small WEGS Cluster (U.S. Wind Energy Association)	0.015	0.050	750		50										<3.5	Prototype in 80
Giromill (McDonnell Aircraft Company)	0.510	0.500	910	18	97/204■	10	40	1,574					5.5			Conceptual
Offshore Design (Cluster of 55)	14.9	10.0	1,640#		350					27,830				12.1		Conceptual
Hamilton Standard, 3MW-Model	1.26	3.00	420	31	255	14	50	6,600	10,300	13,500	14,000		2.4‡			Prototype in 81

Note: All costs and energy output are manufacturer projected.

*At hub height.

†At 30 feet height.

‡Fourteen mph.

§Current price (first quarter 1979), not a projection.

■Height/Diameter.

#Dollars per kilowatt delivered-loss in transmission (estimated 9%).

Source: SRI International

- A passive yaw control using a downwind rotor (Hamilton-Standard Wind Turbine)
- Microprocessor control strategies to increase energy output
- Improved airfoil designs to permit better aerodynamic performance
- Multispeed generators to permit variable rotor speeds, thereby maximizing tip to wind speed ratio (Westinghouse patent recently acquired)
- Fixed-pitch blades to reduce complexity of fabrication.

Potential future technology and manufacturing improvements include:

- Improved rotor aerodynamics
- Nacelle optimization through component rearrangement
- Reduced blade costs from material or manufacturing innovations
- More flexible tower reducing the cost
- Improved drive train efficiency and reduced weight
- Erection and installation simplifications
- System designs for high reliability and ease of maintenance (Ramler and Donovan, 1979).

A cascade effect results from improvements made on the HAWT design. For instance, using a new lighter material for the blade will reduce the loads on the tower, the gear box, the bearings, and other parts, permitting the use of smaller components. Thus, an improvement in blade

design can reduce costs in many other wind machine components as well. This kind of effect has already been experienced in moving from the MOD 1 to the MOD 1A system, and significant cost reductions have resulted.

Hamilton Standard Horizontal Axis Wind Turbine

Hamilton Standard is developing a multimegawatt wind turbine for Sweden.* It has many innovative features that might improve performance and reduce costs, including:

- Use of a 3-MW, 2-blade, 77.6-m-diameter rotor
- Free yaw, downwind
- Fillament wound fiberglass blades (fatigue unlimited and easily automated)
- Full span pitch control
- An 80-m tower.

Alcoa Darrieus Design

The Alcoa Darrieus wind turbine is of interest because it is commercially available now in a range of sizes up to 500 kW. The 500-kW Darrieus (rated at 8.05 m/sec) costs $380/kW. Its cost is not expected to be greatly reduced because its design is simple. The next-generation machine has the following features:

- A 5-MW, 3-blade, 25 x 8.8 m rotor
- Extruded aluminum blades

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*The equipment should become operational in 1981 (Gregoire, 1979).

- A 0.17-m, 112-kW model tested extensively by Sandia
- Less interference with television and FM-radio reception than expected for HAWTs (Sengupta, 1979).
- Commercially available
- Being used by an Oregon utility
- MW model in design stage.

Such machines are expected to reduce current turbine costs by 35-40%, and the total installed cost will be reduced by about 25% through design improvements. These design improvements for the Darrieus wind turbine include:

- Use of cambered airfoils or nonuniform planforms to improve aerodynamics
  - The blade efficiency can increase from 0.39 to 0.41
  - The maximum efficiency will be experienced at a higher tip-speed-to-wind-speed ratio
- Reducing structural requirements to HAWT standards
  - Reducing maximum wind speed from 67.5 to 53.6 m/sec (150 to 120 mph)
  - Lowering cut-out speed from 26.8 to 17.88 m/sec (60 to 40 mph)
  - Reducing tower buckling safety factor from 10 to 5
  - Reducing blade wall thickness (Kadlec, 1979).

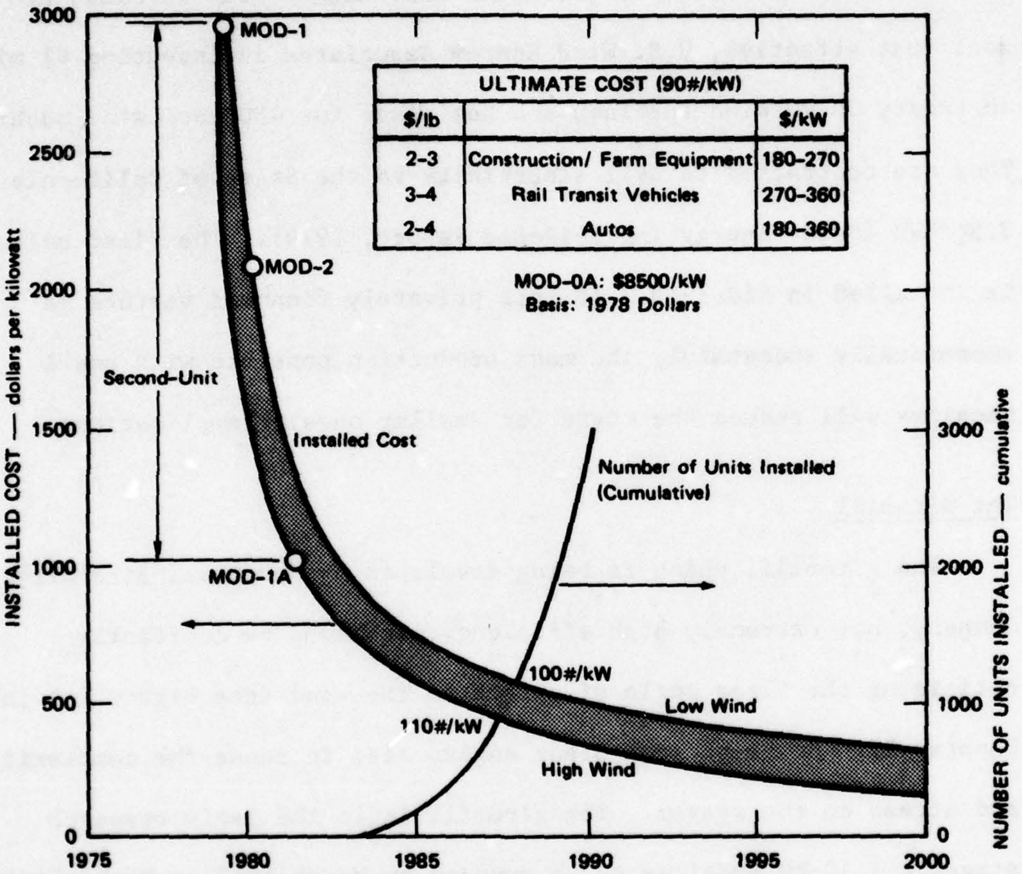
General Electric MOD 1A Progress Report

MOD 1A is a 2-MW, 2-blade, downwind HAWT. It has a softer tower and a more compact nacelle assembly than the MOD 1. It also has tip control rather than full-span pitch control. Its capital costs are two-thirds less than those of the MOD 1. General Electric is seeking commercial orders for the system; the company's projections indicate that costs will be further reduced as production increases (see Figure 7-1).

The Schachle Design

Wind Power Products, Inc., has contracted with Southern California Edison to install a 3-MW Schachle wind turbine. The available information is shown in Table 7-1. Some unique features of this design may reduce the cost of electricity. These include:

- The entire tubular steel tower rotates, thus eliminating the heavy yaw system on top of the tower and reducing tower costs.
- The generator is at ground level linked to the turbine by a hydraulic pump-motor. A less complex gear box can be used, which reduces the weight atop the tower even more.
- Three laminate wood and fiberglass blades are used for allowing low-cost, high-efficiency aerodynamics. (Scheffler, 1979).



SOURCE: Electric Power Research Institute (1979)

FIGURE 7-1 WIND ECONOMICS LARGE SCALE SYSTEMS

This unit should be operational by November 1, 1979. Modifications would be necessary for use in the New Hampshire area to maintain the rotational capabilities of the tower in snow and ice conditions.

50-kW Wind Turbine Farm Concept

Although the analysis indicates that larger wind turbines are the most cost effective, U.S. Wind Energy Associates is investing $1 million in twenty 50-kW wind turbines and has plans for 480 more wind machines. They are contracted to sell electricity to the State of California at 3.5¢/kWh (Solar Energy Intelligence Report, 1979). The first units will be installed in mid-1980. If this privately financed venture is economically successful, the mass production possible with small machines will reduce the costs for smaller on-site applications.

The Giromill

The giromill, which is being developed by McDonnell Aircraft Company, has extremely high efficiency, achieved by constantly optimizing the blade angle of attack to the wind (see Figure 2-1 in Chapter 2). However, such blade angles also increase the complexity and stress on the system. The giromill is in the early research stages. A 40-kW model is to be running by March 1980 at Rocky Flats (Mertz, 1979). Its high efficiency and high stress loading may indicate that it is best used at sites with low wind speeds, but further tests will indicate the extent of the stress loads and their effect on the economics of this system.

Offshore WEGS Feasibility

A recently completed study (Kilar and Chowaniee, 1979) on the feasibility of offshore wind turbine use concluded that:

- Offshore wind is technically feasible.
- Using the field concept, 55 WEGS rated at 3 MW each could produce electricity at approximately 10.2¢/kWh in the Northeast.
- The critical factors that influence the energy costs are mean wind speed, water depth, and maximum survival conditions (distance to shore was not critical).
- Moored floating platforms can support any type of wind turbine in most offshore environments. However, water depth cannot exceed 1,500 ft (465 m).
- Average mean wind speed off the Northeast Coast ranges from 18 to 21 mph (28.8 to 33.6 m/hr) at hub height.

Because comparable wind speeds are anticipated between 3,000 and 4,000 ft elevations in the New England area, and because offshore installations are twice as expensive, offshore WEGS would not be considered until the available land sites are fully utilized.

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Appendix A

TERRAIN MAPS

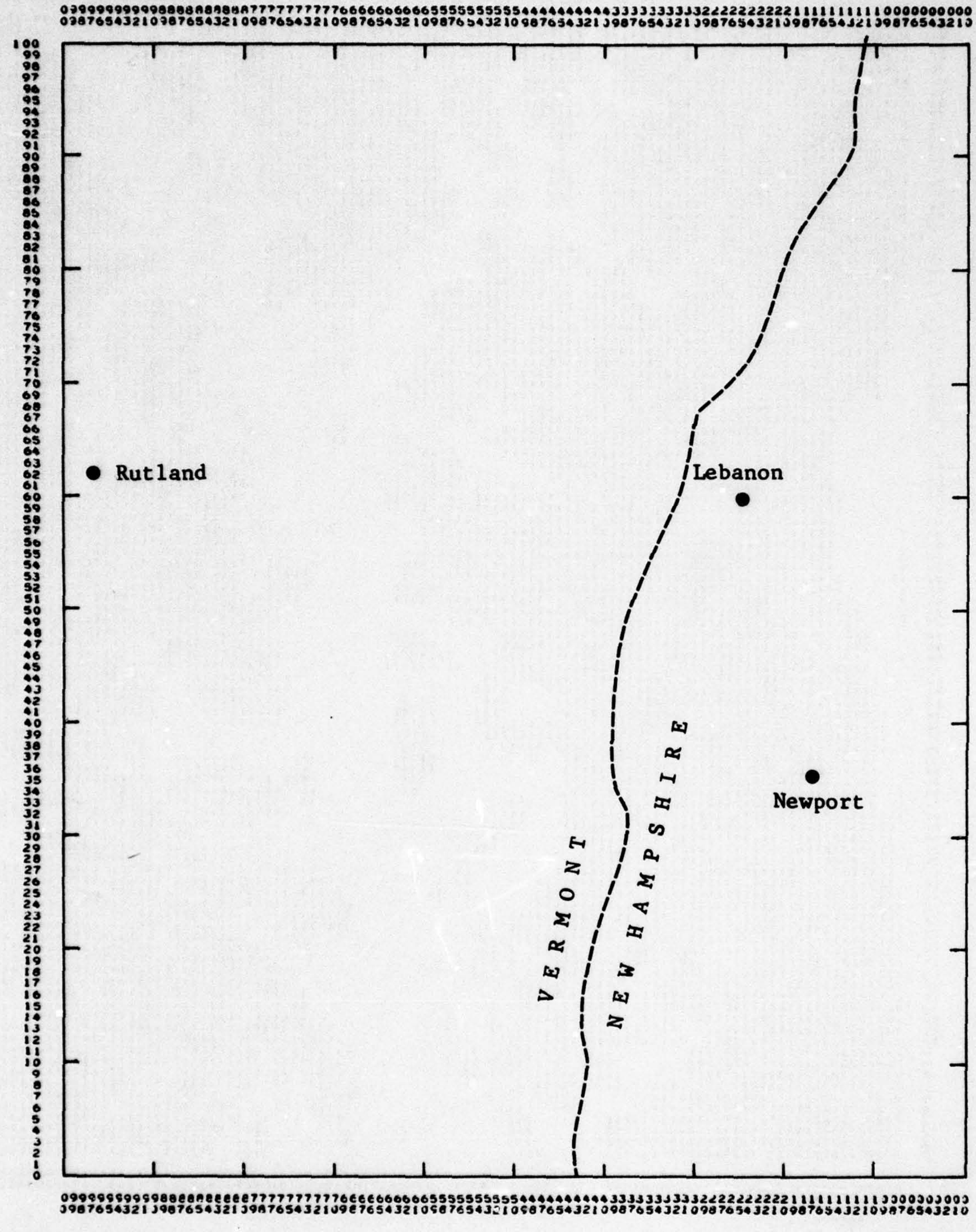
The maps in this section are intended to give a first approximation to the wind resource in northern New England. The power produced by wind generators is strongly dependent on average wind speeds, and the average wind speeds are primarily a function of altitude. The terrain maps correspond to the four sectors identified in Figure 1-10, and show features in different altitude zones that are useful in evaluating the wind resource. Mt. Washington is in the southeast corner of Sector 4. Figure A1 indicates the area enclosed by Sector 1 with tick marks at intervals of 0.1 degrees; the numerals at 0.01 degree increments aid in locating any particular points. Figure A2 is a terrain map of Sector 1 with a height increment of 1,000 ft so that a blank at any location signifies a terrain height less than 1,000 ft, a 1 signifies a terrain height between 1,000 and 2,000 ft, a 2 signifies 2,000 to 3,000 ft, a 3 signifies 3,000 to 4,000 ft, etc. The rest of the terrain maps are given in Figures A3 through A26. Table A1 shows the significance of the symbols for all maps.

The terrain maps have been generated from digital terrain data obtained on magnetic tape from the National Cartographic Information Center of the U.S. Geological Survey at Reston, Virginia. To reduce the original voluminous data to manageable amounts, the terrain heights have been averaged for small areas enclosed by 0.01 degree latitude-longitude boxes. These boxes have dimensions of 0.68 mi (1.1 km) north-south by 0.48 mi (0.77 km) east-west. The smoothed terrain heights are then scaled and printed as shown in Figures A2 through A26.

Table A-1

SYMBOLS USED IN TERRAIN MAPS AND ALTITUDE RANGES IN FEET

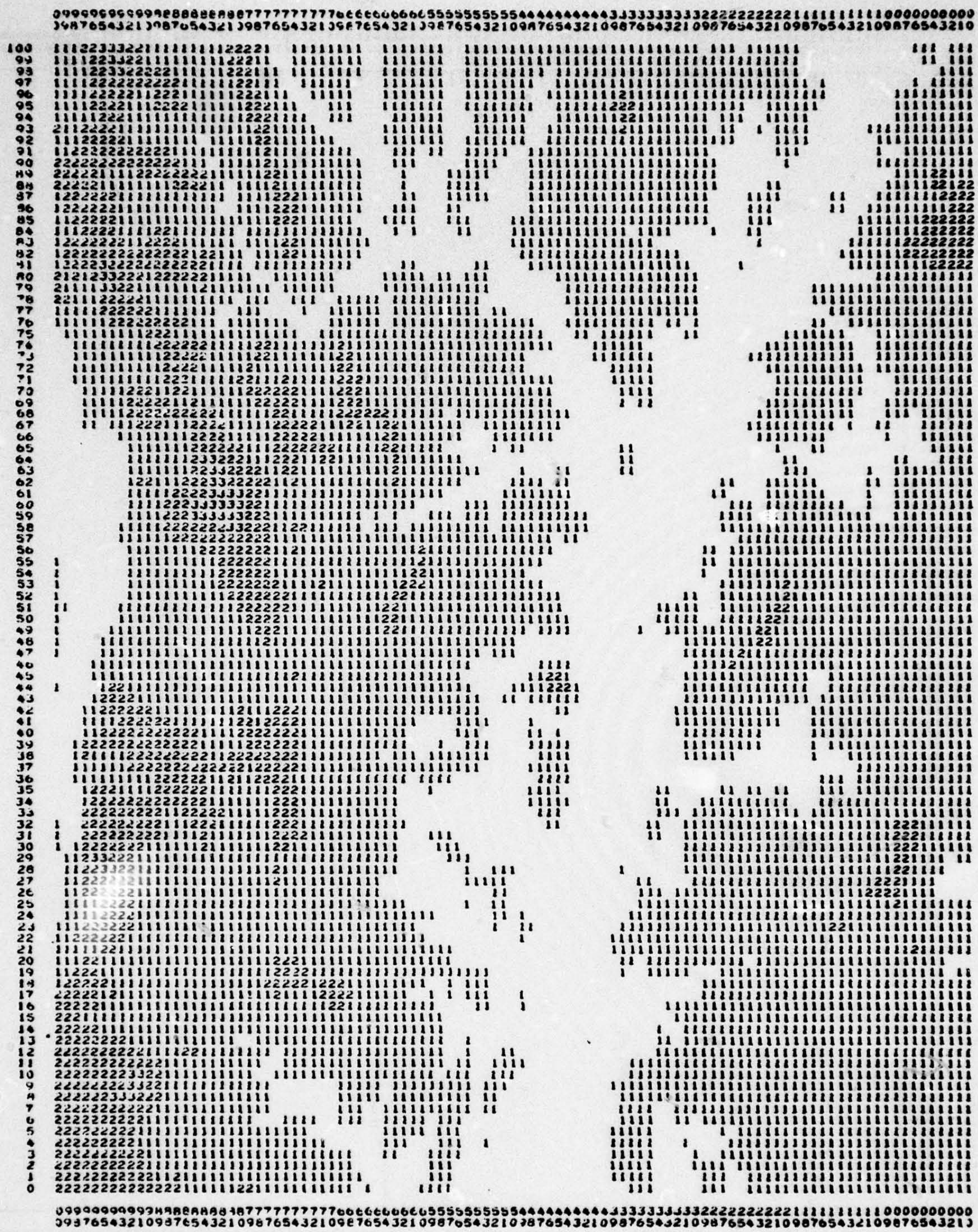
	Figure Numbers						
Symbol	A2, A8, A14, A20	A3, A9, A15, A21	A6, A12, A18, A26	A5, A11, A17, A25	A4, A10, A16, A24	A23	A22
Blank	<1000	<500	<1000 or>2000	<2000 or>3000	<3000 or>4000	<4000 or>5000	<5000 or>6000
0			1000 to 1100	2000 to 2100	3000 to 3100	4000 to 4100	5000 to 5100
1	1000 to 2000	500 to 1000	1100 to 1200	2100 to 2200	3100 to 3200	4100 to 4200	5100 to 5200
2	2000 to 3000	1000 to 1500	1200 to 1300	2200 to 2300	3200 to 3300	4200 to 4300	5200 to 5300
3	3000 to 4000	1500 to 2000	1300 to 1400	2300 to 2400	3300 to 3400	4300 to 4400	5300 to 5400
4	4000 to 5000	2000 to 2500	1400 to 1500	2400 to 2500	3400 to 3500	4400 to 4500	5400 to 5500
5	5000 to 6000	2500 to 3000	1500 to 1600	2500 to 2600	3500 to 3600	4500 to 4600	5500 to 5600
6		3000 to 3500	1600 to 1700	2600 to 2700	3600 to 3700	4600 to 4700	5600 to 5700
7		3500 to 4000	1700 to 1800	2700 to 2800	3700 to 3800	4700 to 4800	5700 to 5800
8		4000 to 4500	1800 to 1900	2800 to 2900	3800 to 3900	4800 to 4900	5800 to 5900
9		4500 to 5000	1900 to 2000	2900 to 3000	3900 to 4000	4900 to 5000	5900 to 6000
A		5000 to 5500					
B		5500 to 6000					



SECTOR 1

THE SOUTHEAST CORNER IS AT LAT. = 43.0 AND LONG. = -72.0

FIGURE A1 OUTLINE OF SECTOR 1



SECTOR 1

THE SOUTHEAST CORNER IS AT LAT. = 43.0 AND LONG. = -72.0

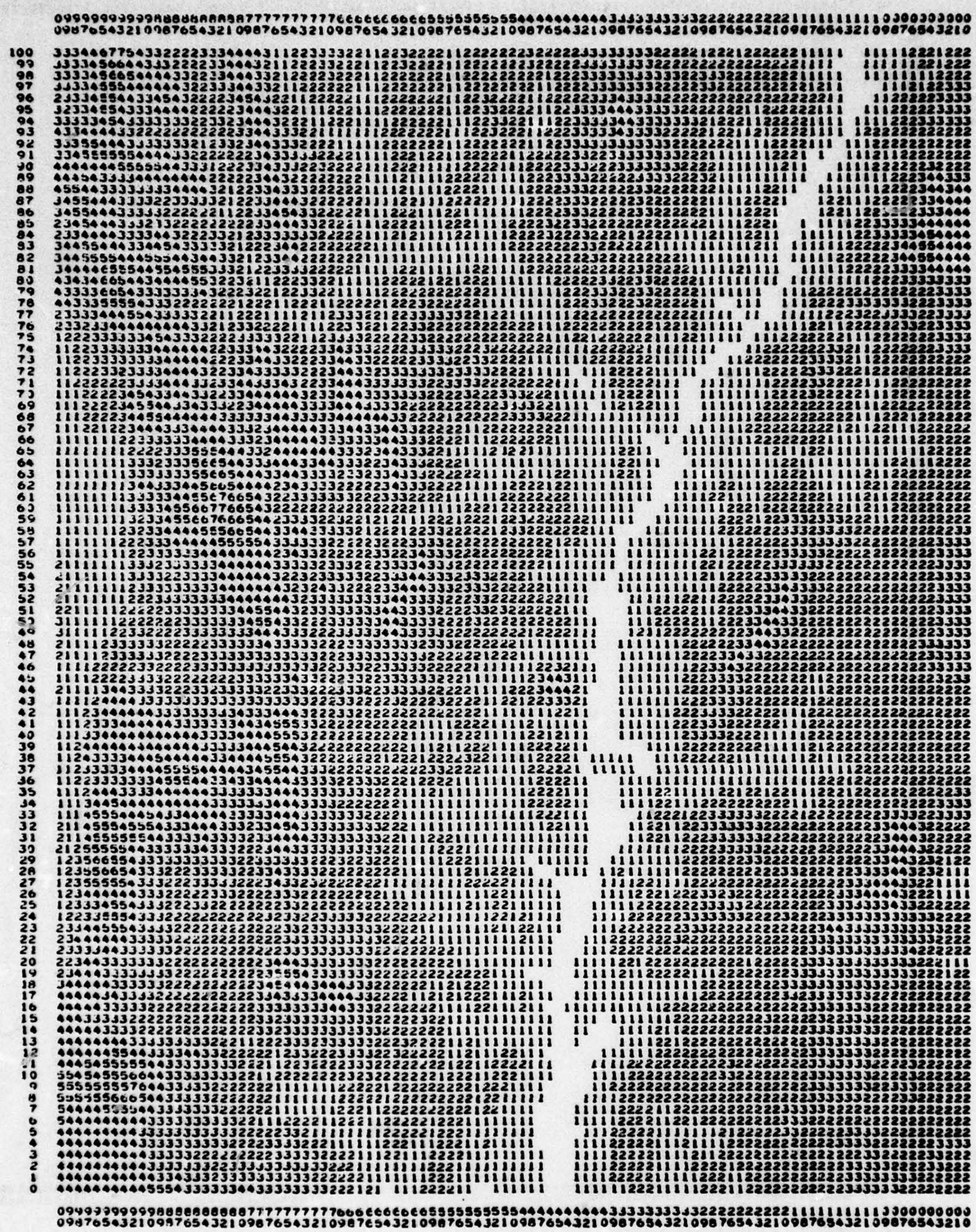
MAP OF TERRAIN HEIGHT BETWEEN 0. AND 6000. FEET

HEIGHT INTERVAL =1000.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 3000.0 FEET IS 20 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN =10201.0 OR 100.0 PERCENT OF THE REGION OR 3421.8 SQ. MILES

FIGURE A2 TERRAIN MAP FOR SECTOR 1. The numbers indicate elevations in increments of 1000 feet



SECTOR 1

THE SOUTHEAST CORNER IS AT LAT. = 43.0 AND LONG. = -72.0

MAP OF TERRAIN HEIGHT BETWEEN 0. AND 6000. FEET

HEIGHT INTERVAL = 500.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 3000.0 FEET IS 20 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN =10201.0 OR 100.0 PERCENT OF THE REGION OR 3421.8 SQ. MILES

FIGURE A3 TERRAIN MAP OF SECTOR 1 WITH ELEVATION INCREMENTS OF 500 FEET

```
     09999999999888888888877777777776666666666555555555544444444443333333333222222222211111111110000000000
     09876543210987654321098765432109876543210987654321098765432109876543210987654321098765432109876543210
100       155
 99        23
 98        00
 97
 96
 95
 94
 93
 92
 91
 90
 89
 88
 87
 86
 85
 84
 83
 82
 81       0
 80       00
 79       11
 78
 77
 76
 75
 74
 73
 72
 71
 70
 69
 68
 67
 66
 65
 64                  31
 63                   30
 62                   12
 61                   4530
 60                 127742
 59                 025320
 58                     12
 57
 56
 55
 54
 53
 52
 51
 50
 49
 48
 47
 46
 45
 44
 43
 42
 41
 40
 39
 38
 37
 36
 35
 34
 33
 32
 31
 30
 29      10
 28       00
 27
 26
 25
 24
 23
 22
 21
 20
 19
 18
 17
 16
 15
 14
 13
 12
 11
 10          31
  9          52
  8        032
  7
  6
  5
  4
  3
  2
  1
  0
     09999999999888888888877777777776666666666555555555544444444443333333333222222222211111111110000000000
     09876543210987654321098765432109876543210987654321098765432109876543210987654321098765432109876543210
```

SECTOR 1

THE SOUTHEAST CORNER IS AT LAT. = 43.0 AND LONG. = -72.0

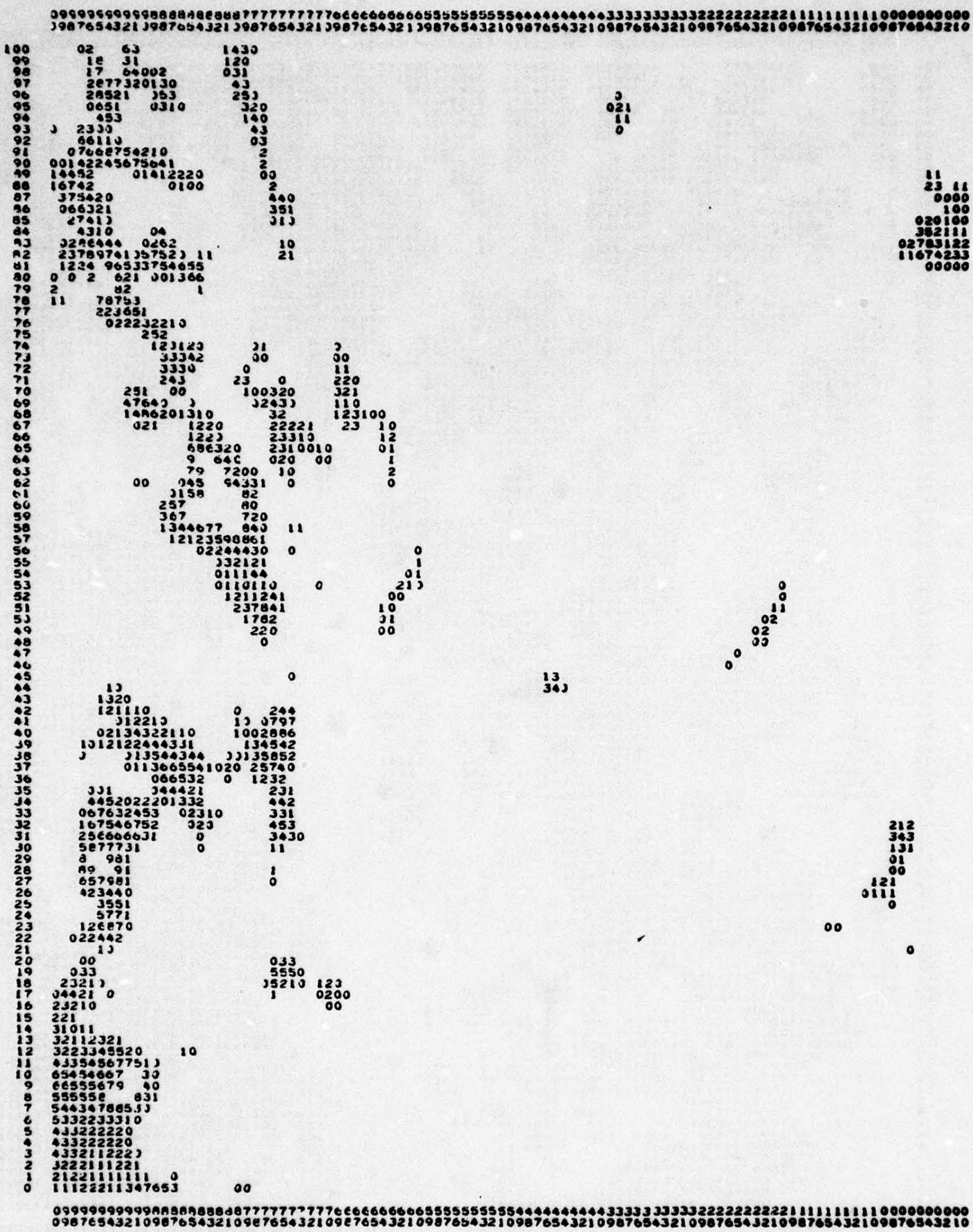
MAP OF TERRAIN HEIGHT BETWEEN 3000. AND 4000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 3500.0 FEET IS 21 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 47.0 OR .5 PERCENT OF THE REGION OR 15.8 SQ. MILES

FIGURE A4 TERRAIN MAP OF ELEVATIONS IN SECTOR 1 BETWEEN 3000 AND 4000 FEET SHOWING 100-FOOT INCREMENTS



SECTOR 1

THE SOUTHEAST CORNER IS AT LAT. = 43.0 AND LONG. = -72.0

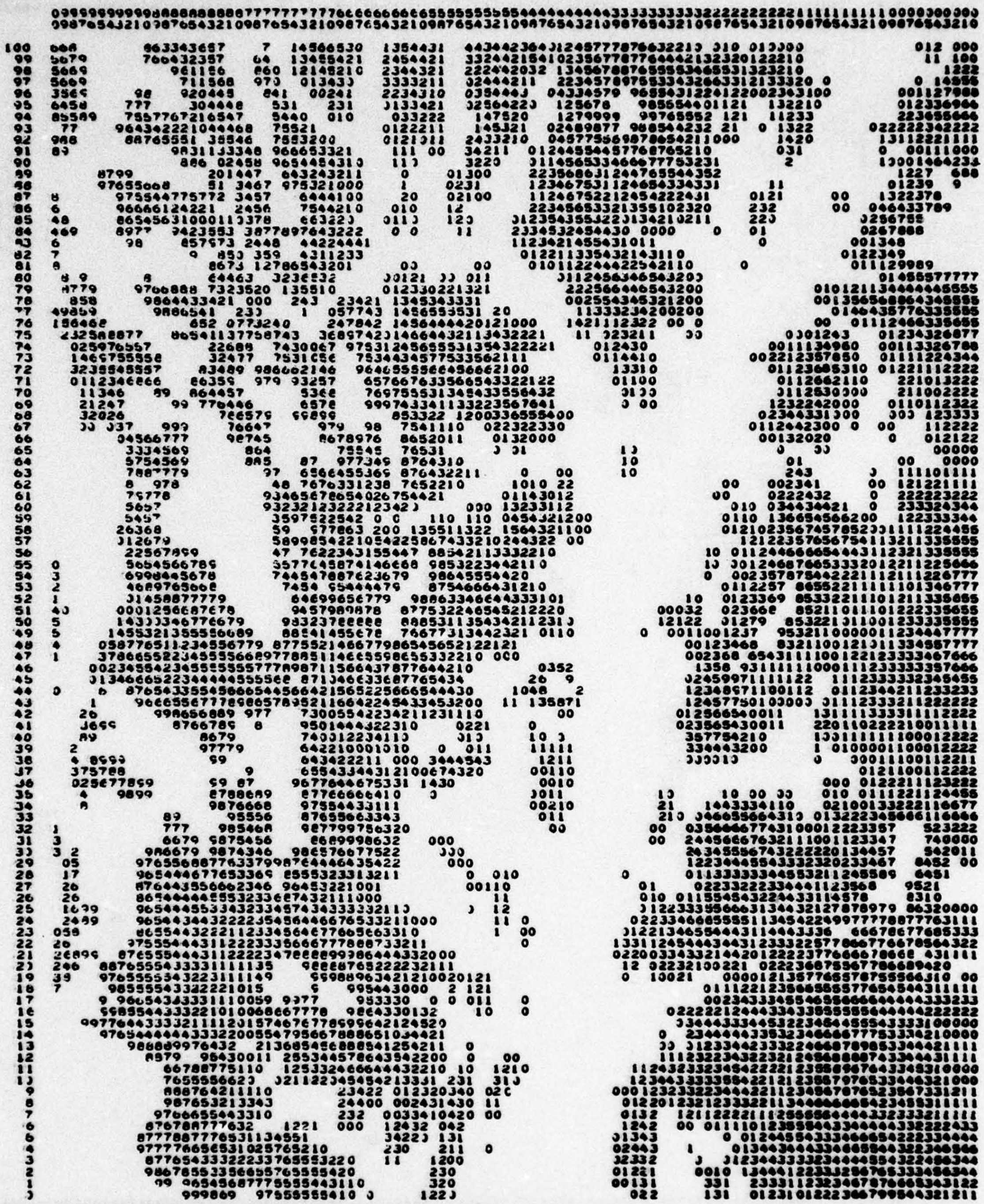
MAP OF TERRAIN HEIGHT BETWEEN 2000. AND 3000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 2500.0 FEET IS 19 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 1342.0 OR 10.2 PERCENT OF THE REGION OR 349.5 SQ. MILES

FIGURE A5 TERRAIN MAP OF ELEVATIONS IN SECTOR 1 BETWEEN 2000 AND 3000 FEET SHOWING 100-FOOT INCREMENTS



SECTOR 1

THE SOUTHEAST CORNER IS AT LAT. = 43.0 AND LONG. = -72.0

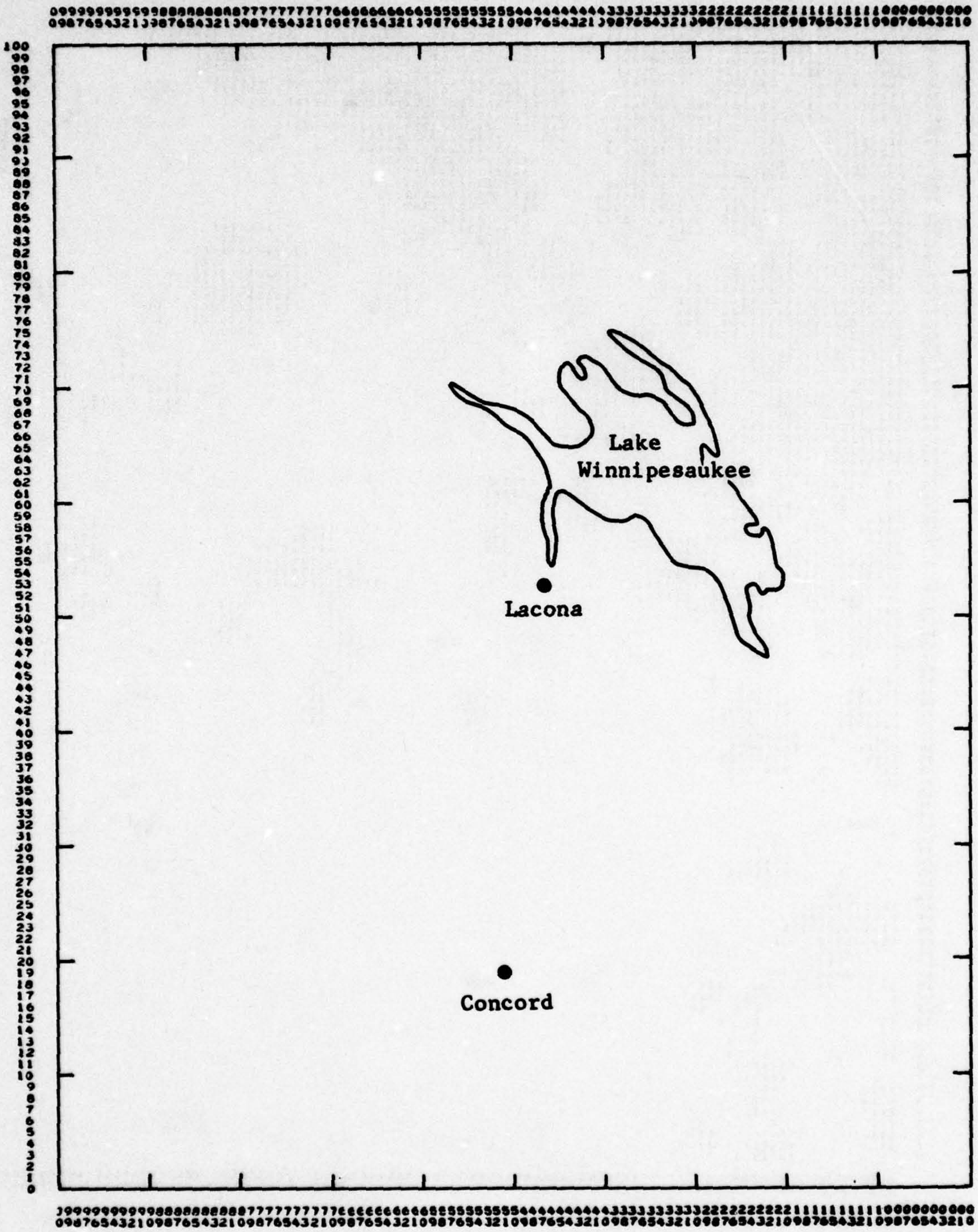
MAP OF TERRAIN HEIGHT BETWEEN 1000. AND 2000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 1500.0 FEET IS 16 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 6384.0 OR 62.6 PERCENT OF THE REGION OF 2141.4 SQ. MILES

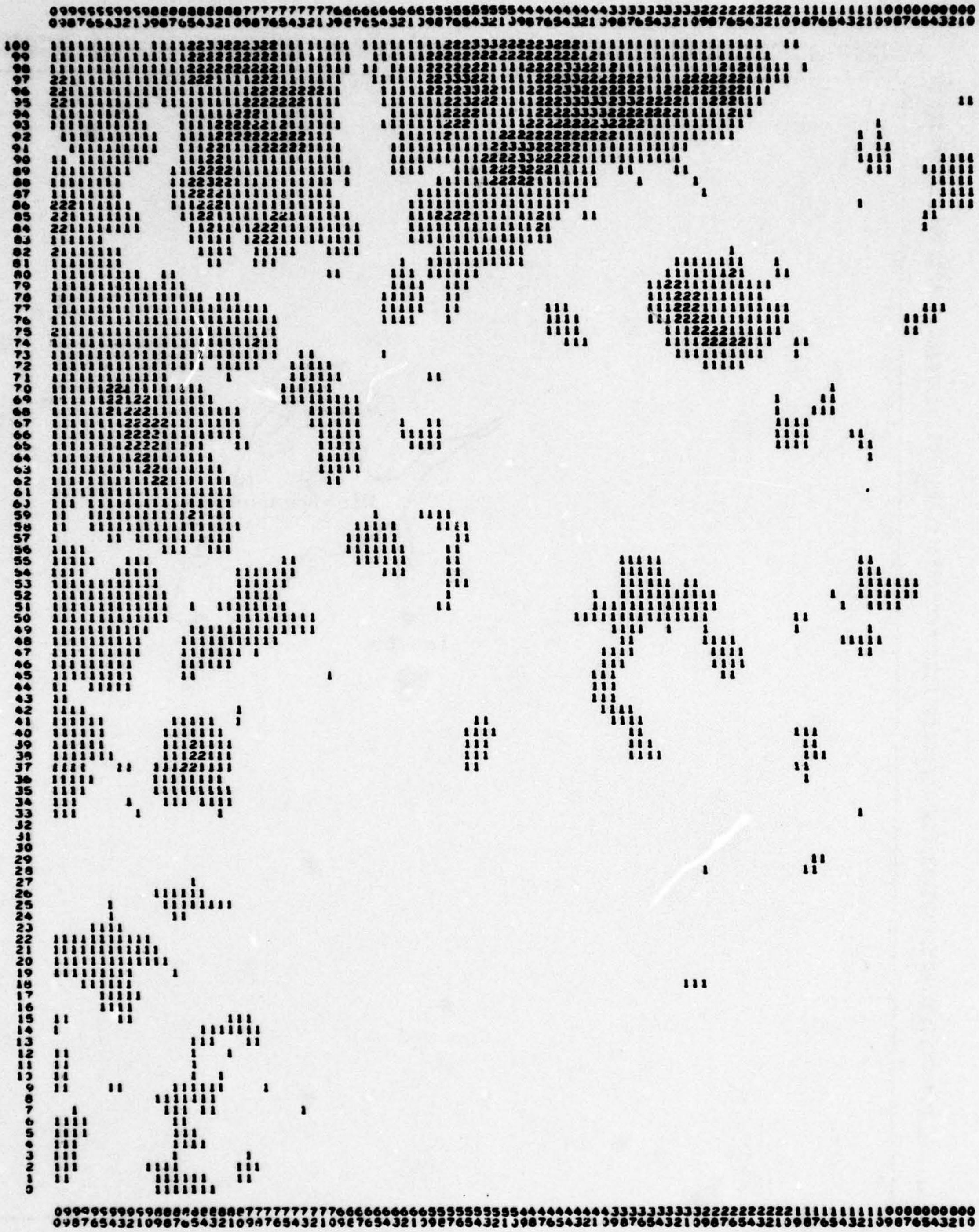
FIGURE A6 TERRAIN MAP OF ELEVATIONS IN SECTOR 1 BETWEEN 1000 AND 2000 FEET SHOWING 100-FOOT INCREMENTS



SECTOR 2

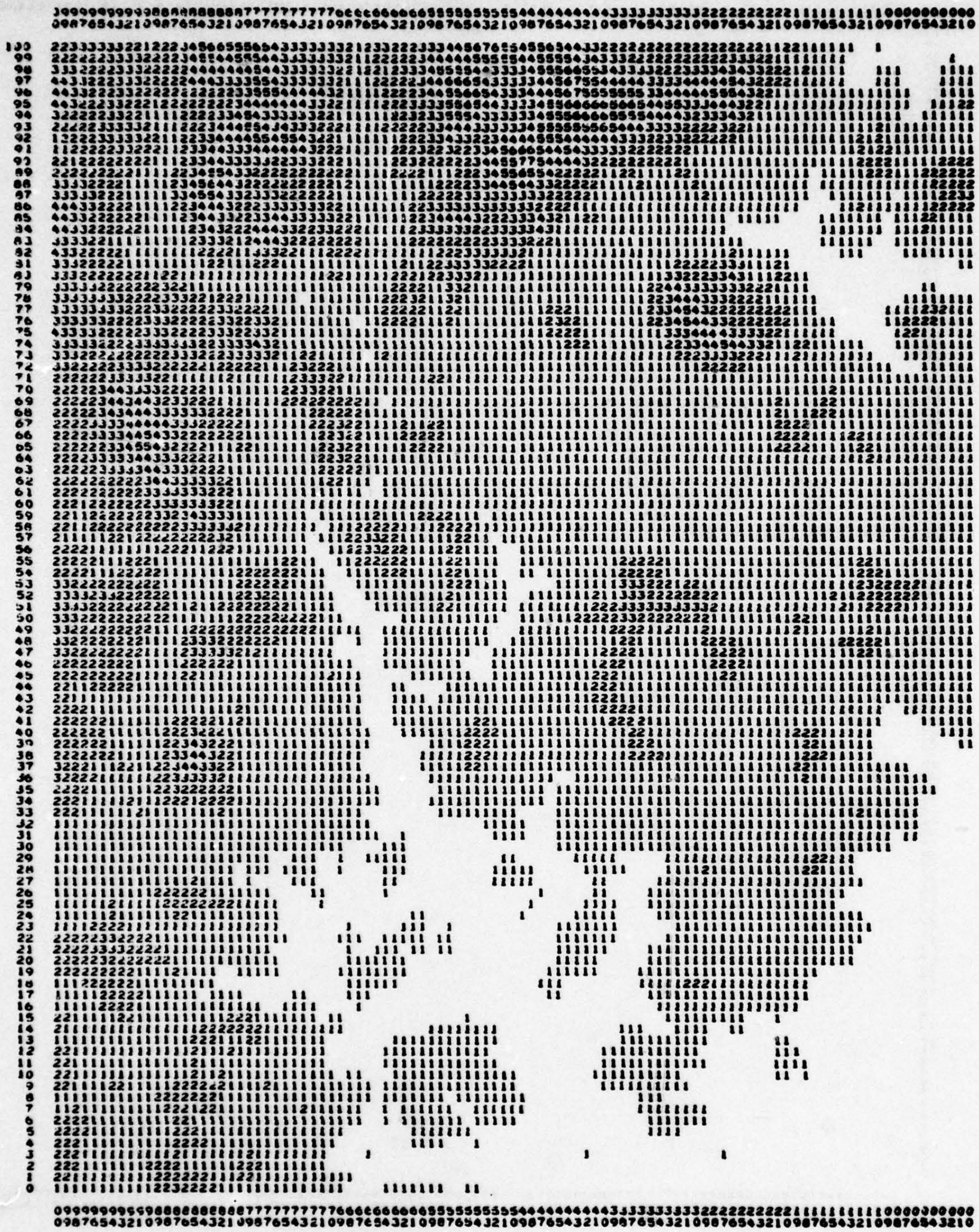
THE SOUTHEAST CORNER IS AT LAT. = 43.0 AND LONG. = -71.0

FIGURE A7 OUTLINE OF SECTOR 2



```
SECTOR  2
THE SOUTHEAST CORNER IS AT LAT. =  43.0  AND LONG. =  -71.0
MAP OF TERRAIN HEIGHT BETWEEN    0. AND 6000. FEET
HEIGHT INTERVAL =1000.0
THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 3000.0 FEET IS  20 MPH
THE NUMBER OF .01 DEGREE AREAS SHOWN =10201.0 OR 100.0 PERCENT OF THE REGION OR 3421.8 SQ. MILES
```

FIGURE A8 TERRAIN MAP FOR SECTOR 2. The numbers indicate elevations in increments of 1000 feet



SECTOR 2

THE SOUTHEAST CORNER IS AT LAT. = 43.0 AND LONG. = -71.0

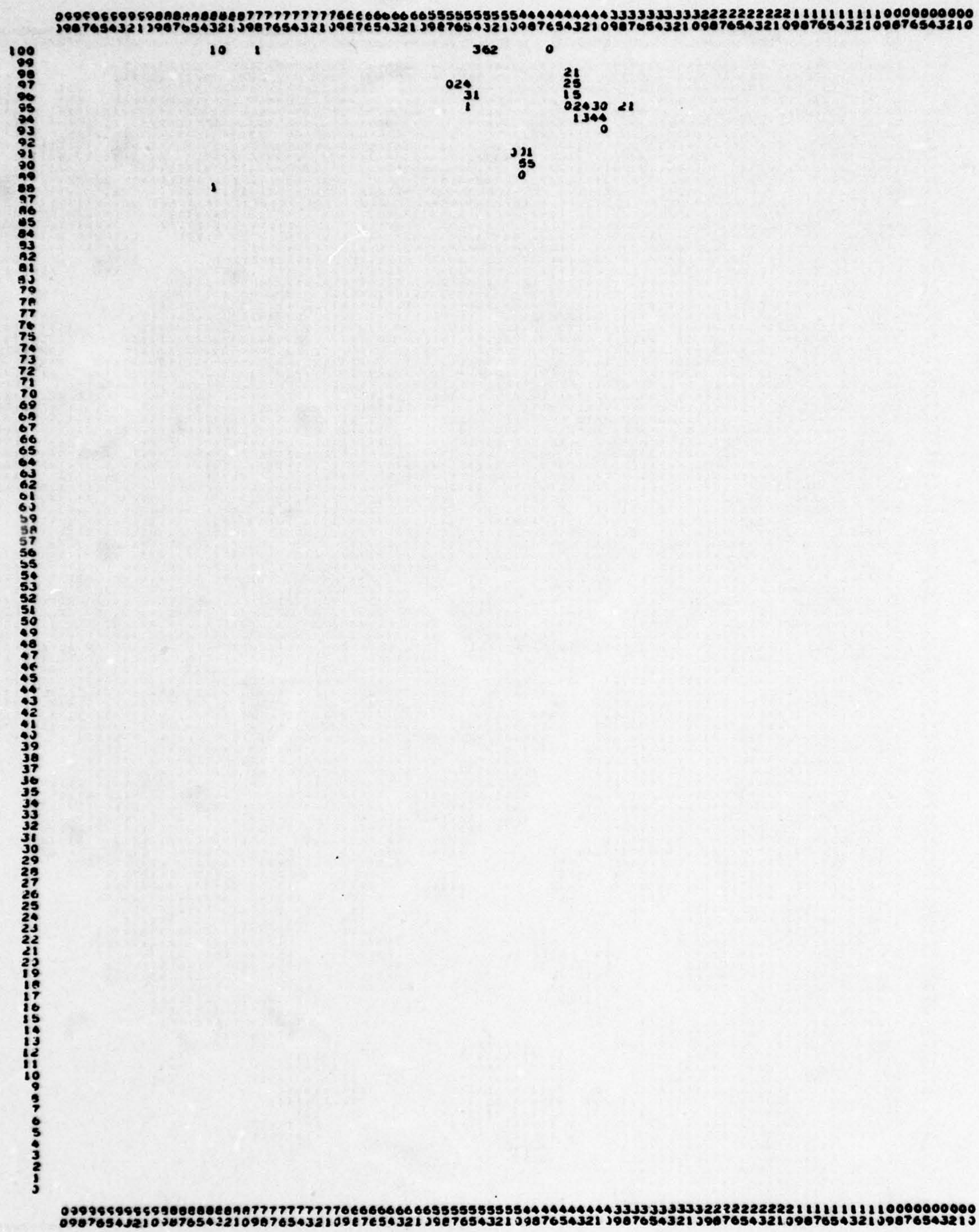
MAP OF TERRAIN HEIGHT BETWEEN 0. AND 6300. FEET

HEIGHT INTERVAL = 500.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 3000.0 FEET IS 20 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN =10201.0 OR 100.0 PERCENT OF THE REGION OR 3421.8 SQ. MILES

FIGURE A9 TERRAIN MAP OF SECTOR 2 WITH ELEVATION INCREMENTS OF 500 FEET



SECTOR 2

THE SOUTHEAST CORNER IS AT LAT. = 43.0 AND LONG. = -71.0

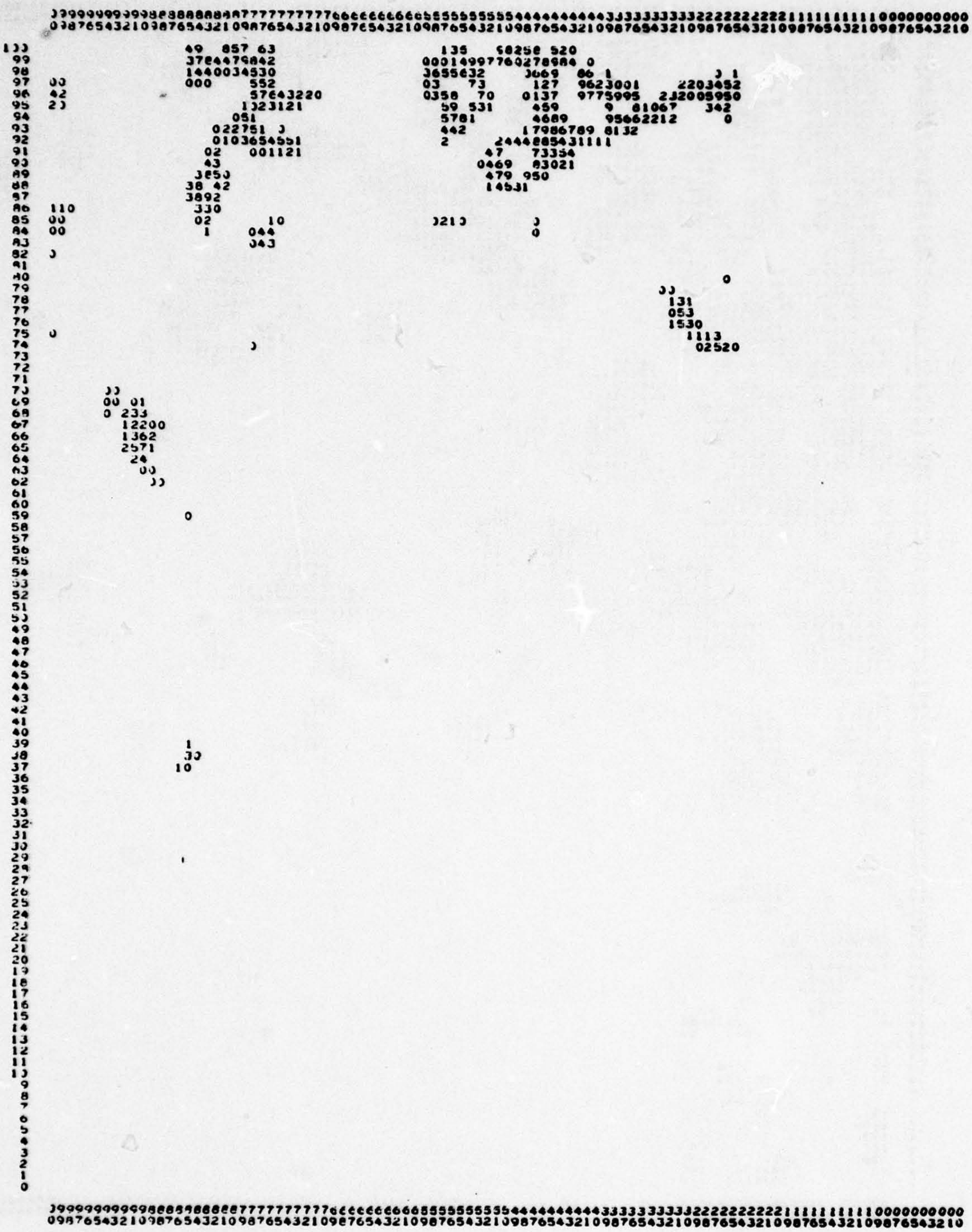
MAP OF TERRAIN HEIGHT BETWEEN 3000. AND 4000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 3500.0 FEET IS 21 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 38.0 OR .4 PERCENT OF THE REGION OR 12.7 SQ. MILES

FIGURE A10 TERRAIN MAP OF ELEVATIONS IN SECTOR 2 BETWEEN 3000 AND 4000 FEET SHOWING 100-FOOT INCREMENTS



SECTOR 2

THE SOUTHEAST CORNER IS AT LAT. = 43.0 AND LONG. = -71.0

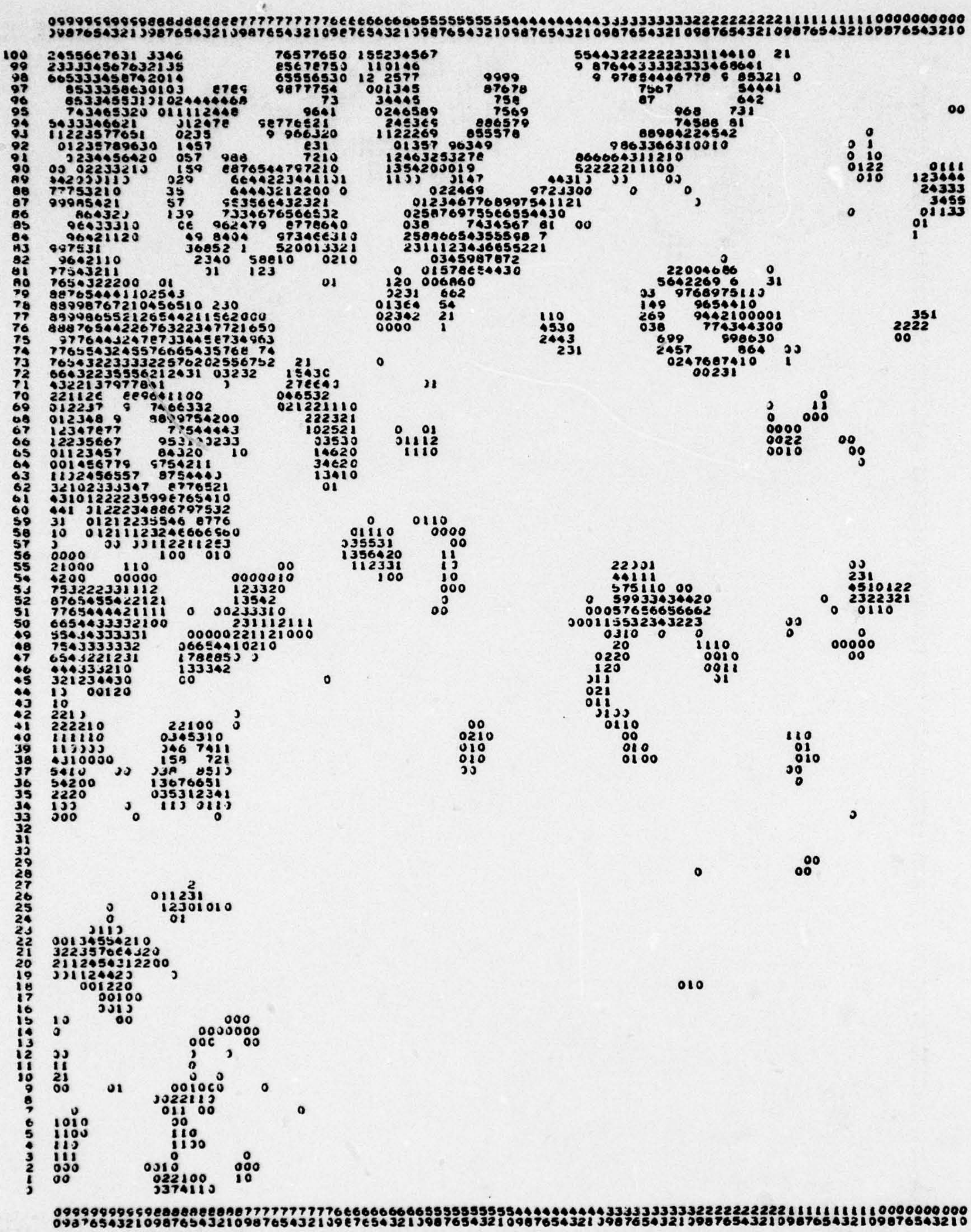
MAP OF TERRAIN HEIGHT BETWEEN 2000. AND 3000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 2500.0 FEET IS 19 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 365.0 OR 3.6 PERCENT OF THE REGION OR 122.4 SQ. MILES

FIGURE A11 TERRAIN MAP OF ELEVATIONS IN SECTOR 2 BETWEEN 2000 AND 3000 FEET SHOWING 100-FOOT INCREMENTS



SECTOR 2

THE SOUTHEAST CORNER IS AT LAT. = 43.0 AND LONG. = -71.0

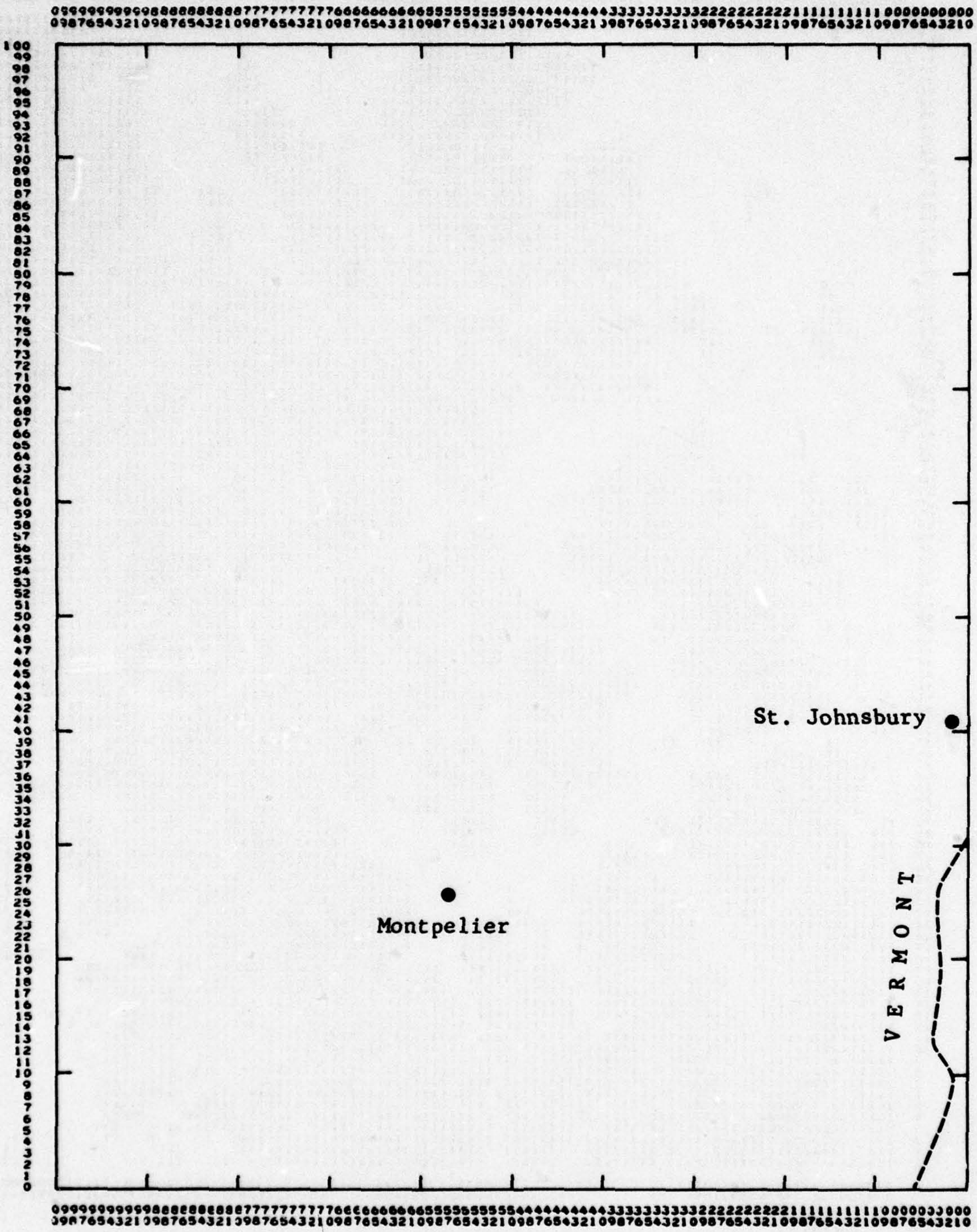
MAP OF TERRAIN HEIGHT BETWEEN 1000. AND 2000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 1500.0 FEET IS 16 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 2318.0 OR 22.7 PERCENT OF THE REGION OR 777.5 SQ. MILES

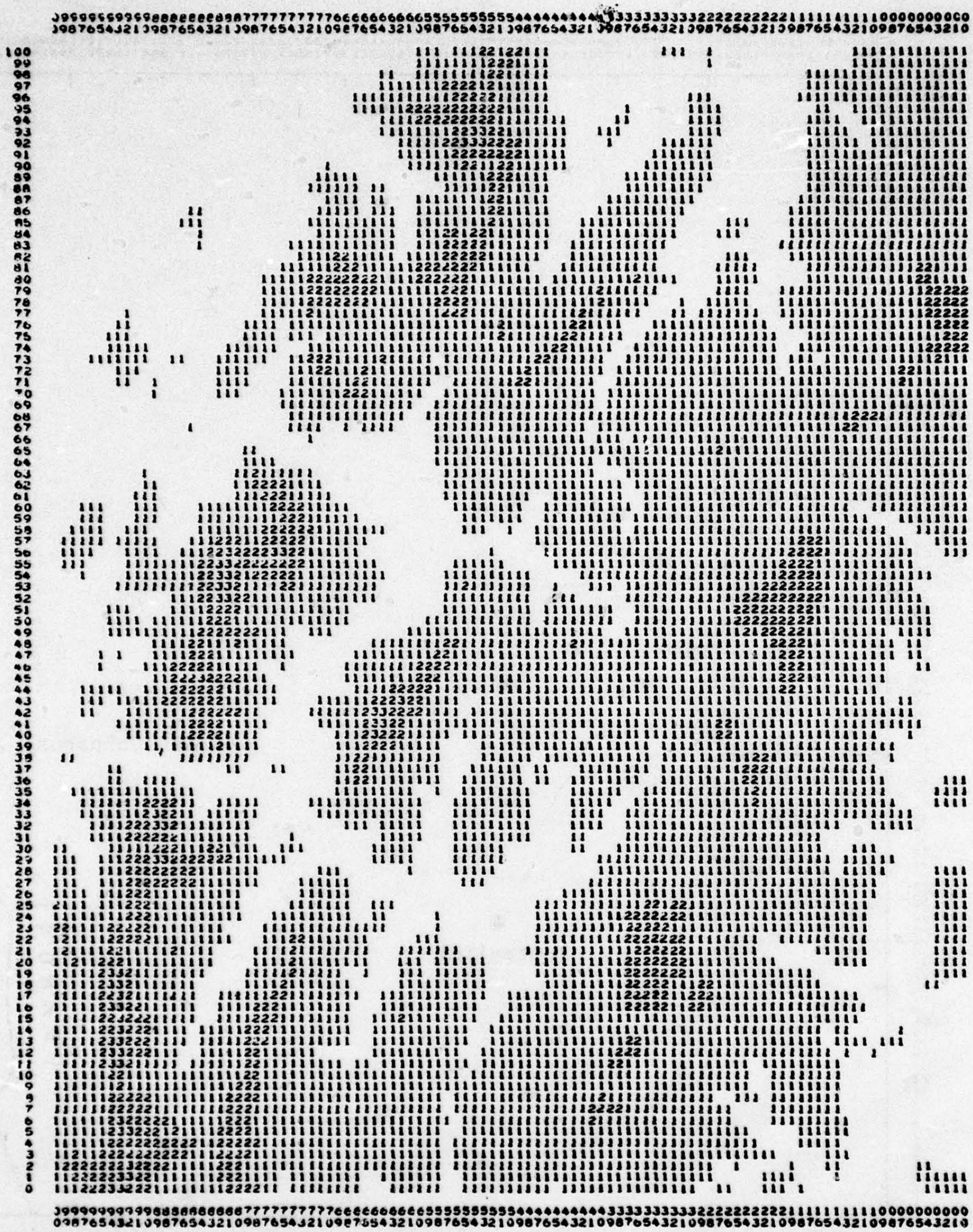
FIGURE A12 TERRAIN MAP OF ELEVATIONS IN SECTOR 2 BETWEEN 1000 AND 2000 FEET SHOWING 100-FOOT INCREMENTS



SECTOR 3

THE SOUTHEAST CCRNER IS AT LAT. = 44.0 AND LONG. = -72.0

FIGURE A13 OUTLINE OF SECTOR 3



SECTOR 3

THE SOUTHEAST CORNER IS AT LAT. = 44.0 AND LONG. = -72.0

MAP OF TERRAIN HEIGHT BETWEEN 0. AND 6000. FEET

HEIGHT INTERVAL =1000.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 3000.0 FEET IS 20 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN =10201.0 OR 133.0 PERCENT OF THE REGION OR 3421.8 SQ. MILES

FIGURE A14 TERRAIN MAP FOR SECTOR 3. The numbers indicate elevations in increments of 1000 feet

SECTOR 3

THE SOUTHEAST CORNER IS AT LAT. = 44.0 AND LONG. = -72.0

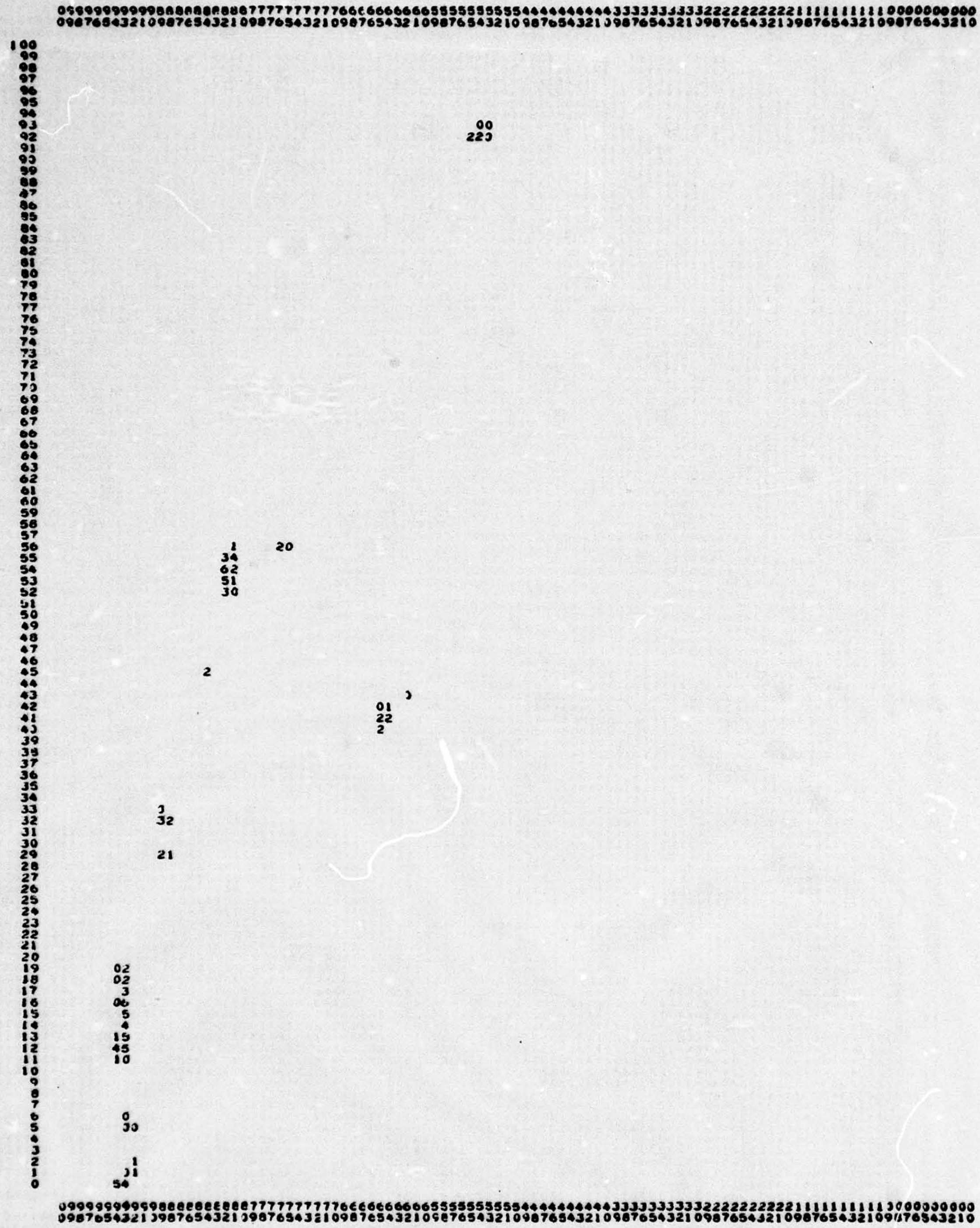
MAP OF TERRAIN HEIGHT BETWEEN 0. AND 6000. FEET

HEIGHT INTERVAL = 500.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 3000.0 FEET IS 20 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN =10201.0 OR 100.0 PERCENT OF THE REGION OR 3421.8 SQ. MILES

FIGURE A15 TERRAIN MAP OF SECTOR 3 WITH ELEVATION INCREMENTS OF 500 FEET



SECTOR 3

THE SOUTHEAST CORNER IS AT LAT. = 44.0 AND LONG. = -72.0

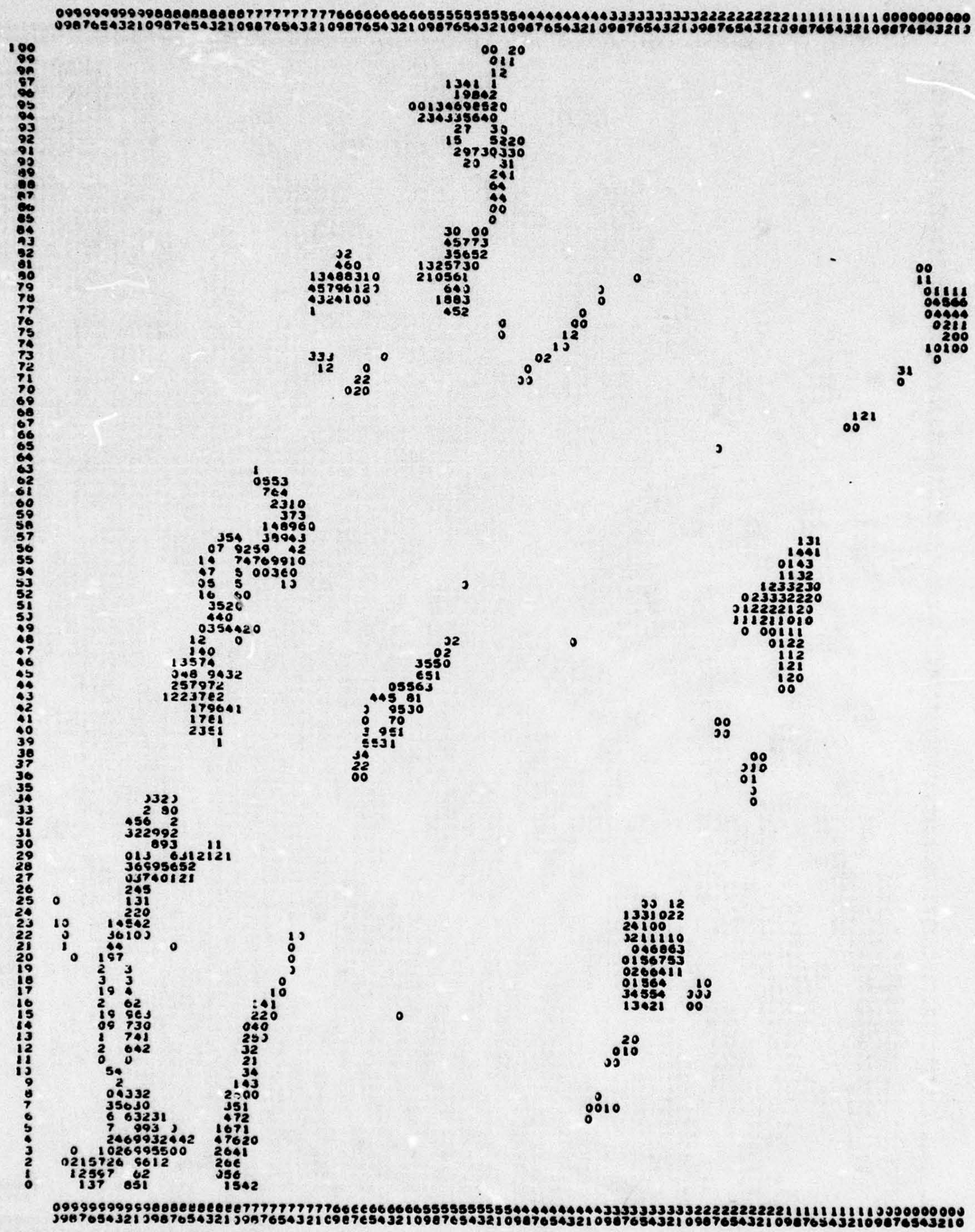
MAP OF TERRAIN HEIGHT BETWEEN 3000. AND 4000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 3500.0 FEET IS 21 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 51.0 OR .5 PERCENT OF THE REGION OR 17.1 SQ. MILES

FIGURE A16 TERRAIN MAP OF ELEVATIONS IN SECTOR 3 BETWEEN 3000 AND 4000 FEET SHOWING 100-FOOT INCREMENTS



SECTOR 3

THE SOUTHEAST CORNER IS AT LAT. = 44.0 AND LONG. = -72.0

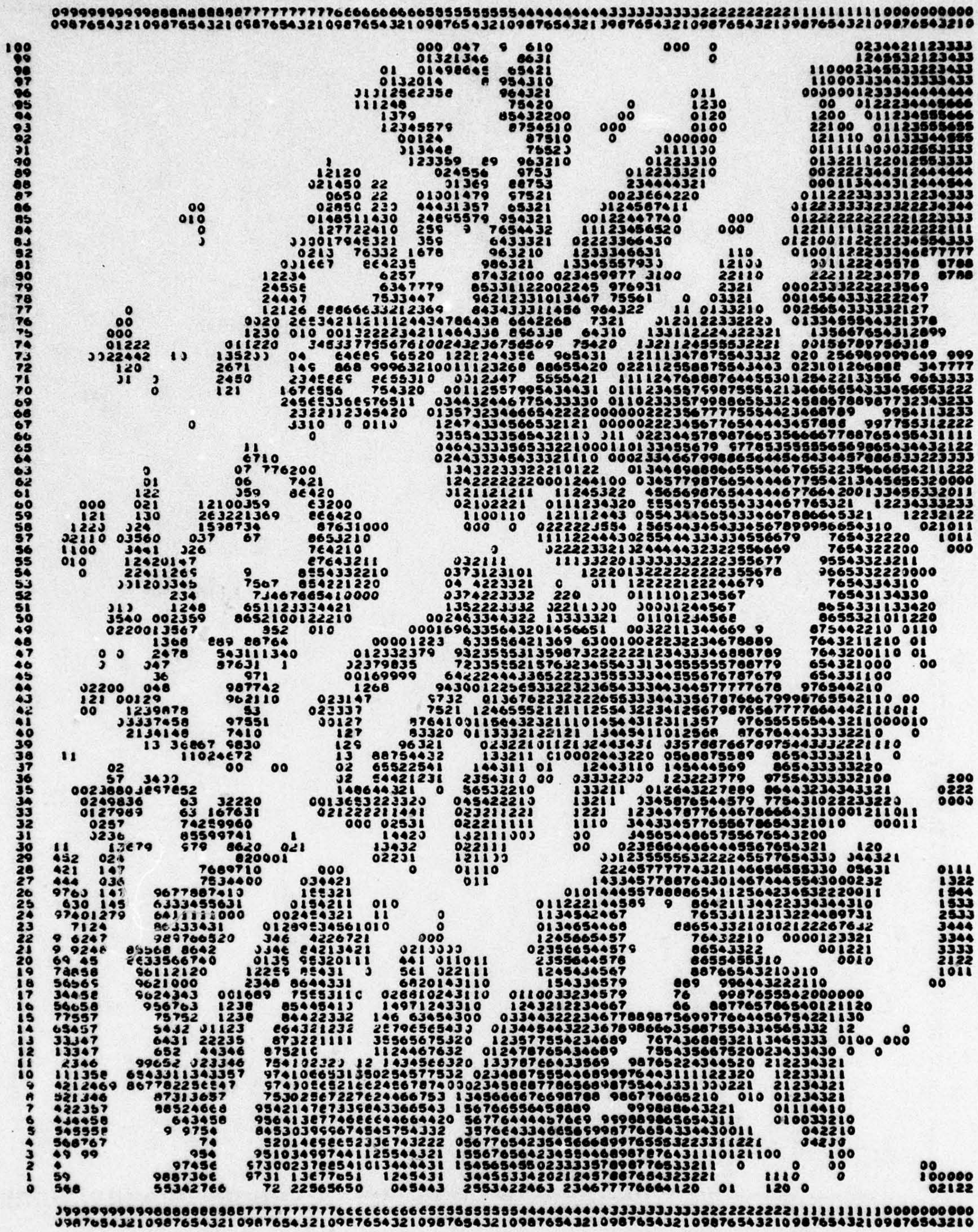
MAP OF TERRAIN HEIGHT BETWEEN 2000. AND 3000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 2500.0 FEET IS 19 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 778.0 OR 7.6 PERCENT OF THE REGION OR 261.0 SQ. MILES

FIGURE A17 TERRAIN MAP OF ELEVATIONS IN SECTOR 3 BETWEEN 2000 AND 3000 FEET SHOWING 100-FOOT INCREMENTS



SECTOR 3

THE SOUTHEAST CORNER IS AT LAT. = 44.0 AND LONG. = -72.0

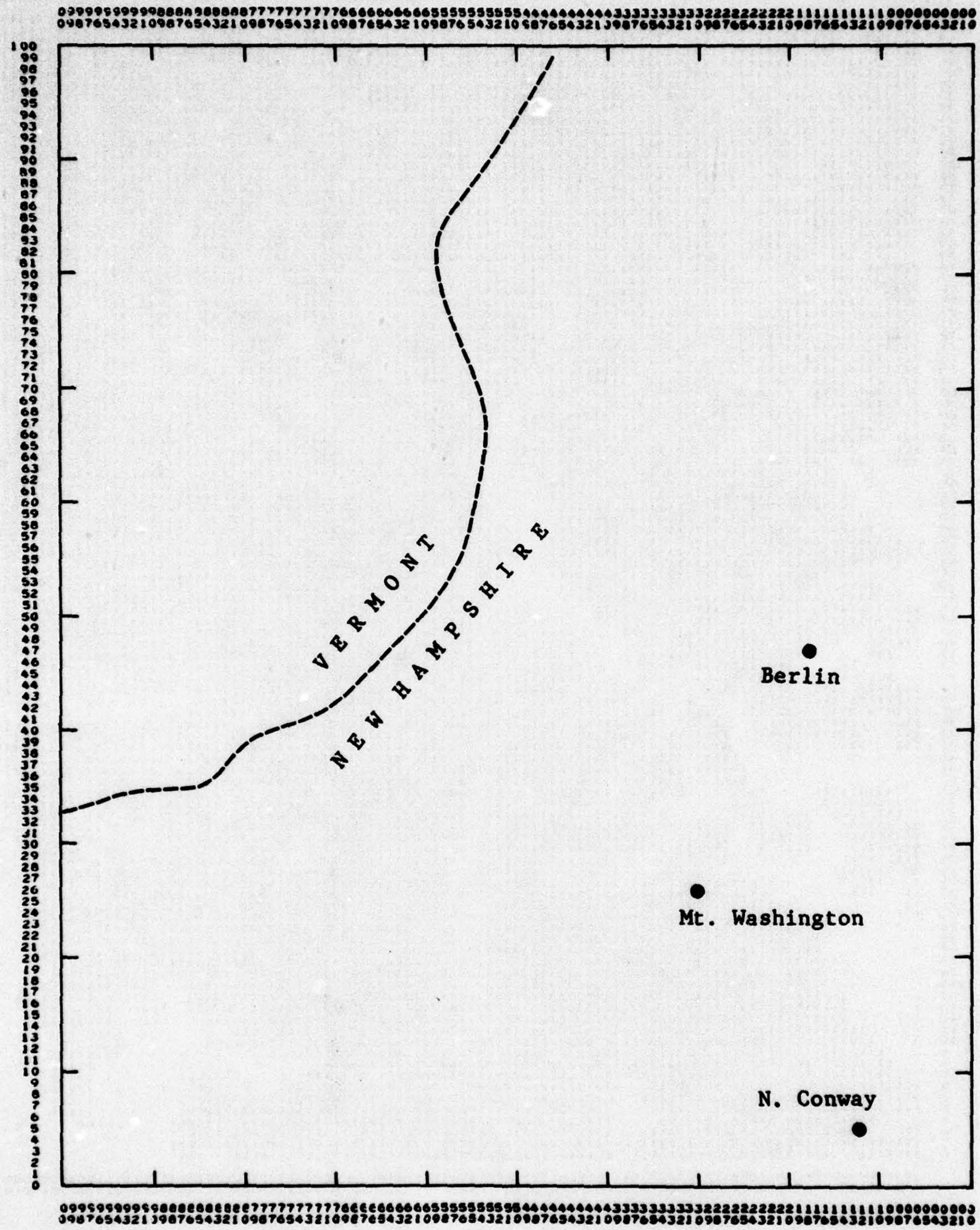
MAP OF TERRAIN HEIGHT BETWEEN 1000. AND 2000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 1500.0 FEET IS 16 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 6133.0 OR 60.1 PERCENT OF THE REGION OR 2057.2 SQ. MILES

FIGURE A18 TERRAIN MAP OF ELEVATIONS IN SECTOR 3 BETWEEN 1000 AND 2000 FEET SHOWING 100-FOOT INCREMENTS



SECTOR 4

THE SOUTHEAST CORNER IS AT LAT. = 44.0 AND LONG. = -71.0

FIGURE A19 OUTLINE OF SECTOR 4

SECTOR 4

THE SOUTHEAST CORNER IS AT LAT. = 44.0 AND LONG. = -71.0

MAP OF TERRAIN HEIGHT BETWEEN 0. AND 6000. FEET

HEIGHT INTERVAL =1000.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 3000.0 FEET IS 20 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN =10201.0 OR 100.0 PERCENT OF THE REGION OR 3421.8 SQ. MILES

FIGURE A20 TERRAIN MAP FOR SECTOR 4. The numbers indicate elevations in increments of 1000 feet

SECTOR 4

THE SOUTHEAST CORNER IS AT LAT. = 44.0 AND LONG. = -71.0

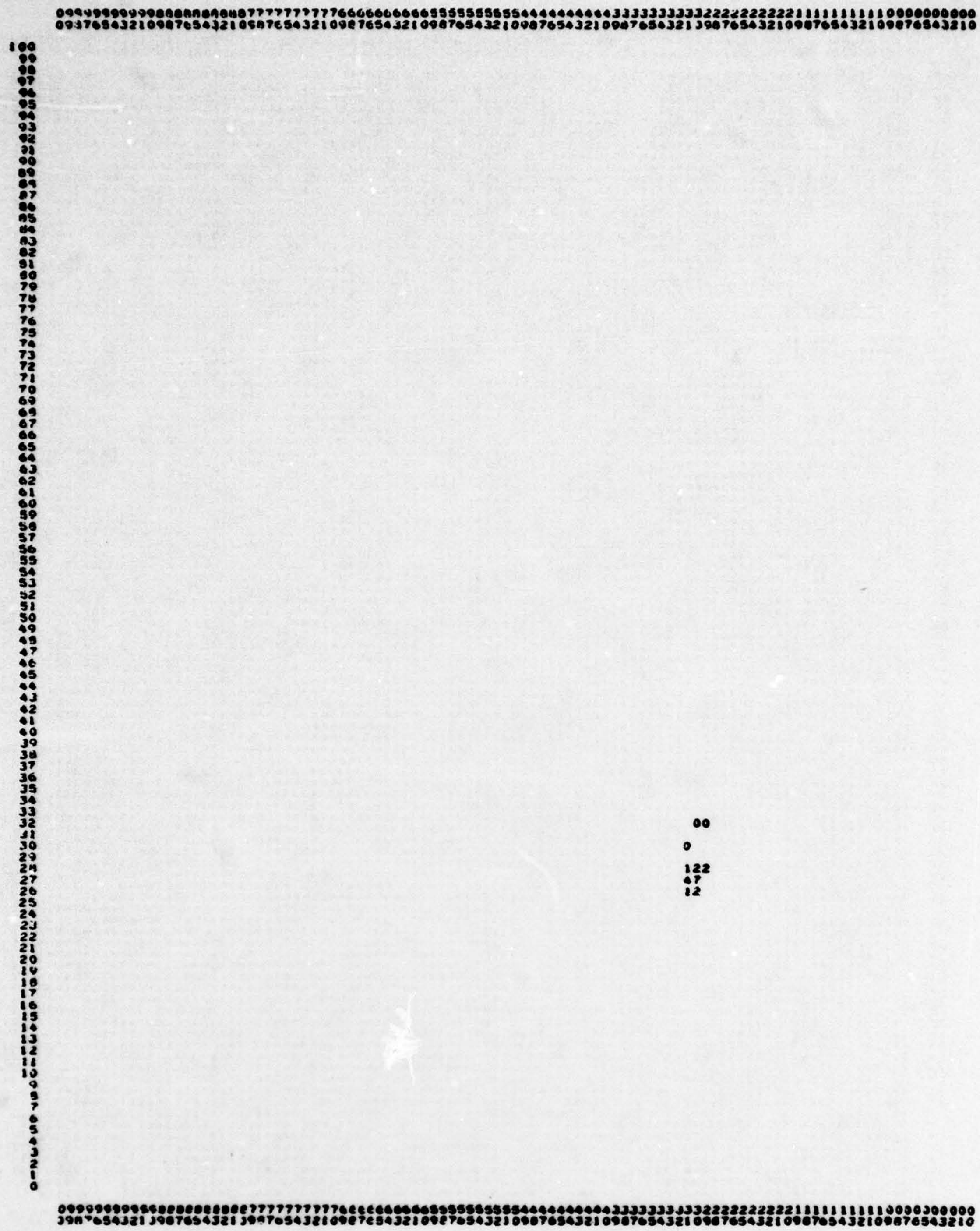
MAP OF TERRAIN HEIGHT BETWEEN 0. AND 6000. FEET

HEIGHT INTERVAL = 500.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 3000.0 FEET IS 20 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN =10201.0 OR 100.0 PERCENT OF THE REGION OR 3421.8 SQ. MILES

FIGURE A21 TERRAIN MAP OF SECTOR 4 WITH ELEVATION INCREMENTS OF 500 FEET



SECTOR 4

THE SOUTHEAST CORNER IS AT LAT. = 44.0 AND LONG. = -71.0

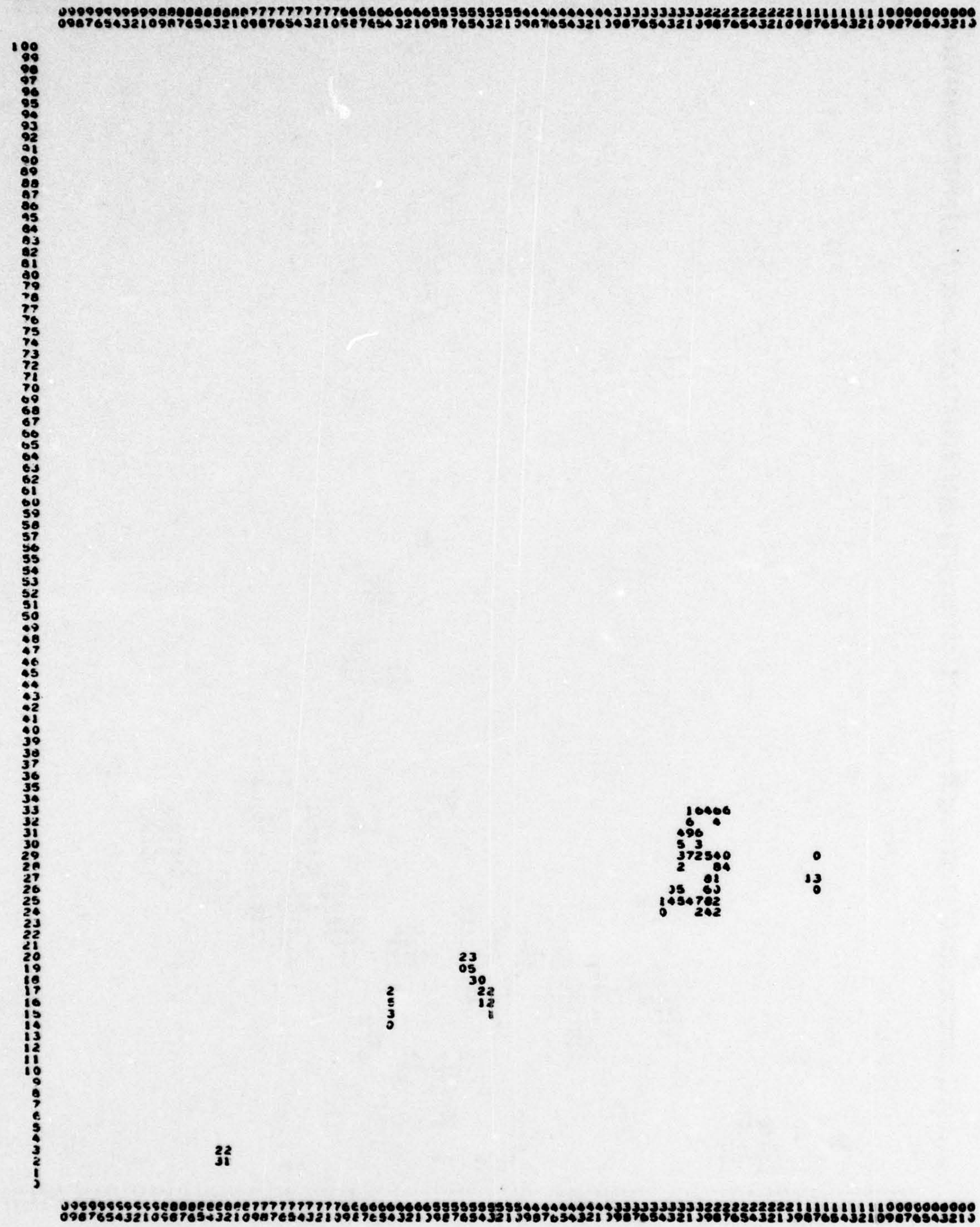
MAP OF TERRAIN HEIGHT BETWEEN 5000. AND 6000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 5533.3 FEET IS 24 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 10.0 OR .1 PERCENT OF THE REGION OR 3.4 SQ. MILES

FIGURE A22 TERRAIN MAP OF ELEVATIONS IN SECTOR 4 BETWEEN 5000 AND 6000 FEET SHOWING 100-FOOT INCREMENTS



SECTOR 4

THE SOUTHEAST CORNER IS AT LAT. = 44.0 AND LONG. = -71.0

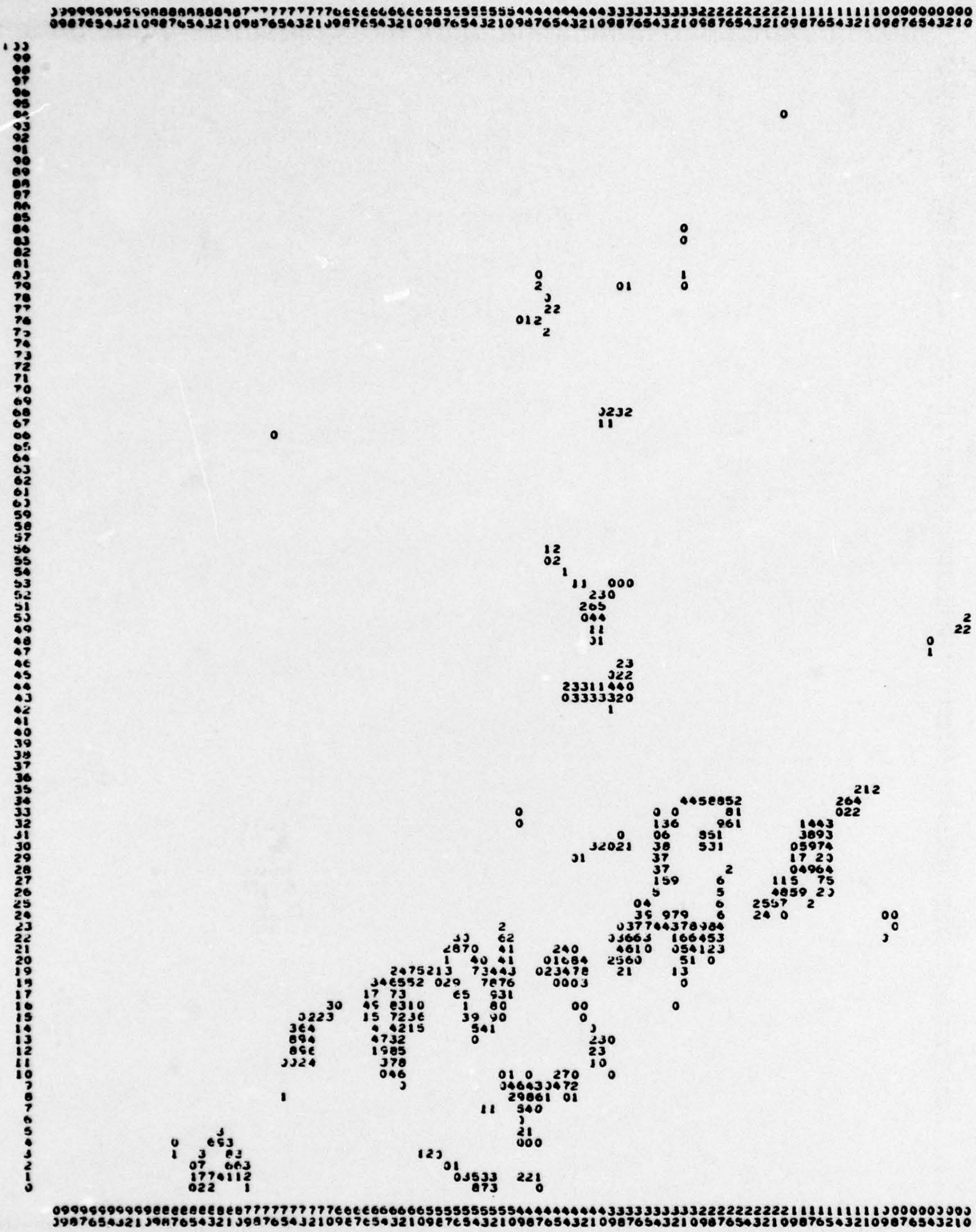
MAP OF TERRAIN HEIGHT BETWEEN 4000. AND 5000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 4500.0 FEET IS 22 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 61.0 OR .6 PERCENT OF THE REGION OR 20.5 SQ. MILES

FIGURE A23 TERRAIN MAP OF ELEVATIONS IN SECTOR 4 BETWEEN 4000 AND 5000 FEET SHOWING 100-FOOT INCREMENTS



SECTOR 4

THE SOUTHEAST CORNER IS AT LAT. = 44.0 AND LONG. = -71.0

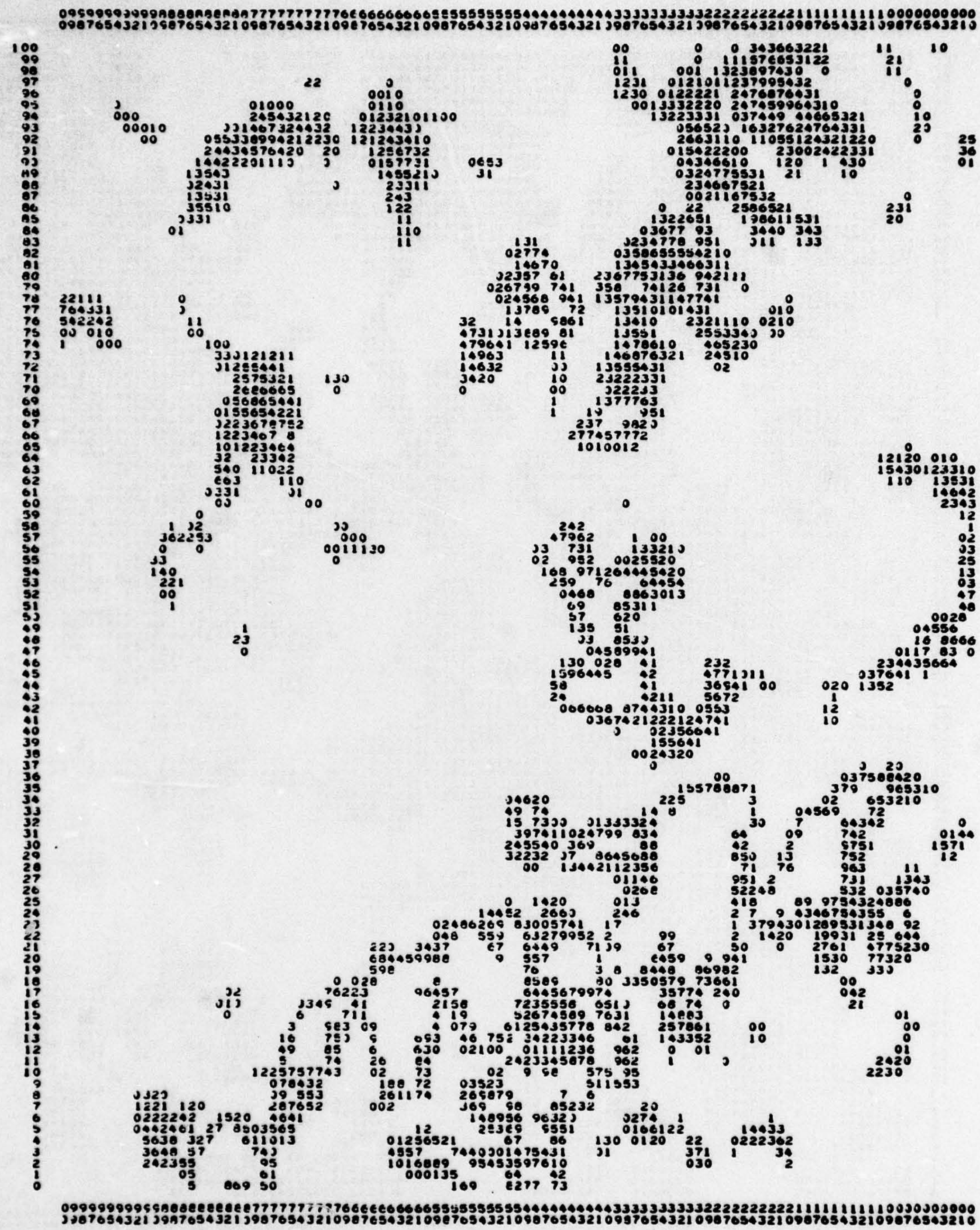
MAP OF TERRAIN HEIGHT BETWEEN 3000. AND 4000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 3500.0 FEET IS 21 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 448.0 OR 4.4 PERCENT OF THE REGION OR 150.3 SQ. MILES

FIGURE A24 TERRAIN MAP OF ELEVATIONS IN SECTOR 4 BETWEEN 3000 AND 4000 FEET SHOWING 100-FOOT INCREMENTS



SECTOR 4

THE SOUTHEAST CORNER IS AT LAT. = 44.0 AND LONG. = -71.0

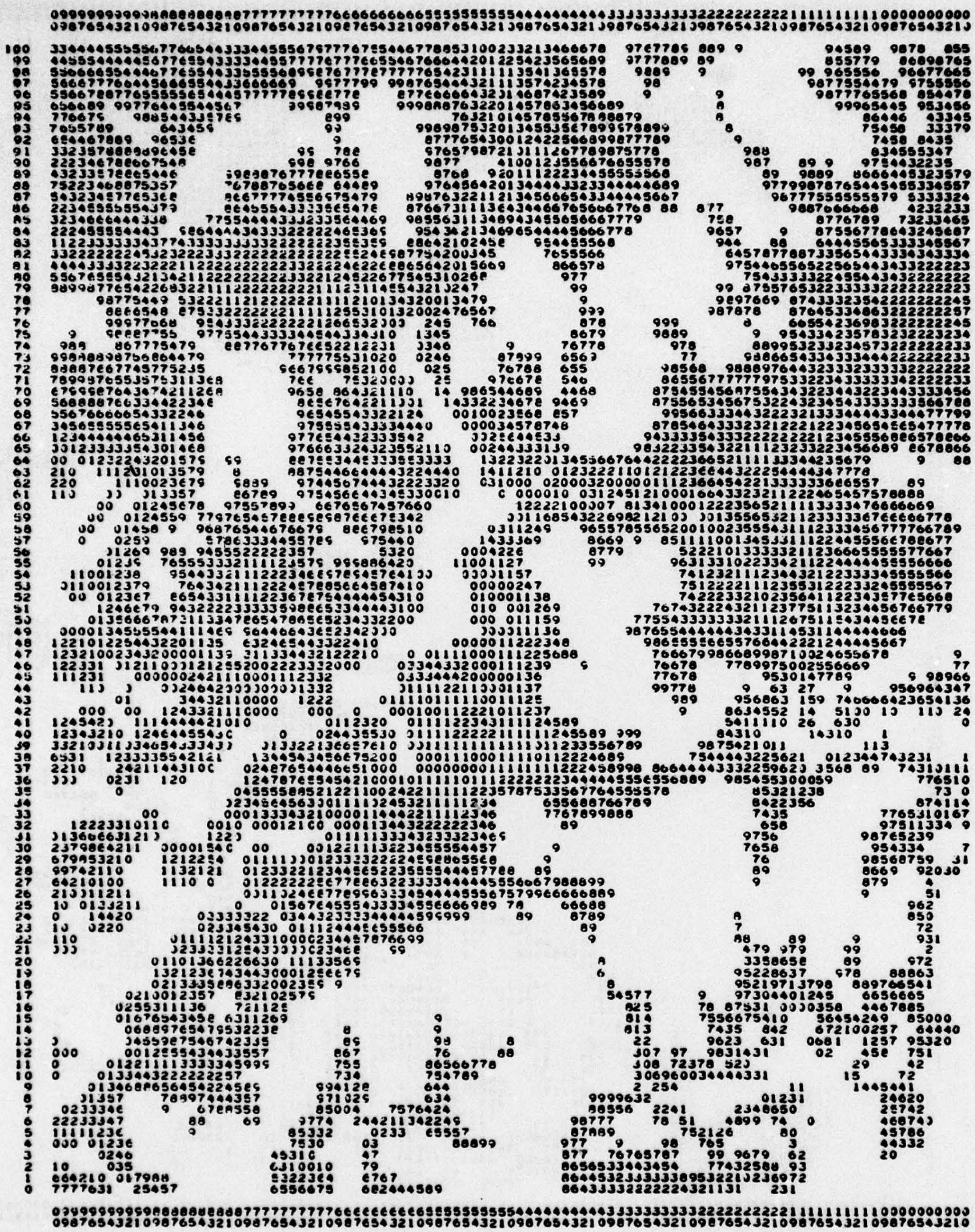
MAP OF TERRAIN HEIGHT BETWEEN 2000. AND 3000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 2500.0 FEET IS 19 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 2270.0 OR 22.3 PERCENT OF THE REGION OR 761.4 SQ. MILES

FIGURE A25 TERRAIN MAP OF ELEVATIONS IN SECTOR 4 BETWEEN 2000 AND 3000 FEET SHOWING 100-FOOT INCREMENTS



SECTOR 4

THE SOUTHEAST CORNER IS AT LAT. = 44.0 AND LONG. = -71.0

MAP OF TERRAIN HEIGHT BETWEEN 1000. AND 2000. FEET

HEIGHT INTERVAL = 100.0

THE APPROXIMATE ANNUAL AVERAGE WIND SPEED AT 1500.0 FEET IS 16 MPH

THE NUMBER OF .01 DEGREE AREAS SHOWN = 6444.0 OR 63.2 PERCENT OF THE REGION OR 2161.6 SQ. MILES

FIGURE A26 TERRAIN MAP OF ELEVATIONS IN SECTOR 4 BETWEEN 1000 AND 2000 FEET SHOWING 100-FOOT INCREMENTS